SUMMARY OF BOARD ITEM

ITEM # 01-9-1: **PUBLIC HEARING TO CONSIDER A PROPOSAL TO ESTABLISH A DISTRIBUTED GENERATION CERTIFICATION PROGRAM AND GUIDANCE FOR THE PERMITTING OF ELECTRICAL GENERATION TECHNOLOGIES**

STAFF RECOMMENDATION: The staff recommends that the Board adopt the proposal to establish a distributed generation certification program and approve the guidance for the permitting of electrical generation technologies.

DISCUSSION: As required by Senate Bill (SB) 1298, the Air Resources Board (ARB) staff is proposing emission standards and certification requirements for electrical generation technologies that are exempt from air district permit requirements, and guidance to the air districts on the permitting of electrical generation technologies that are subject to their regulatory jurisdiction. SB 1298 focuses on electrical generation that is near the place of use, and defines these sources as "distributed generation" (DG).

SB 1298 mandates two levels of emission standards for affected DG technologies. The law requires that the first set of standards become effective no later than January 1, 2003, and reflect the best performance achieved in practice by existing DG technologies that are exempt from district permitting requirements. The law also requires that, by the earliest practicable date, the standards be made equivalent to the level determined by the ARB to be Best Available Control Technology (BACT) for permitted central station power plants in California.

The guidance document must address BACT determinations for DG technologies subject to districts' regulatory jurisdiction and by the earliest practical date, shall make the determinations equivalent to the level determined by the ARB to be BACT for permitted central station power plants in California.

SUMMARY AND IMPACTS:

After January 1, 2003, all new DG units must be certified by the ARB or permitted by an air district before being sold, leased, or used in California. A proposed DG unit that is exempt from the district's permit requirements must be certified by the ARB to defined emission standards. The ARB staff will assist the manufacturers with determining exemption levels for each district. Equipment operating before January 1, 2003 will not be subject to the proposed standards. If a proposed unit is subject to the district's permit requirements, it need not be certified by the ARB before it is sold, leased, or operated in that district. The guidance document will provide assistance to the districts in making permitting decisions for these DG units.

The types of technologies that will be subject to the emission standards include microturbines, reformer-based fuel cells, small reciprocating engines, and external combustion engines.

Manufacturers' efforts to comply with the 2003 emission standards are not expected to result in any significant adverse economic impacts. The overall statewide cost of the proposed certification program for the 2003 standards is estimated to be $370,000 with an estimated individual business cost of $11,000 to $21,500 for source testing, preparing a certification application, and the application fee. Manufacturers' efforts to comply with the 2007 emission standards could result in an adverse economic impact on some manufacturers that must redesign their technologies to meet the more stringent standards. However, credits are included in the staff's proposal for highly efficient technologies and integrated zero emission technology packages to assist manufacturers with meeting the proposed emission standards.

Staff has determined that no significant adverse environmental impact should occur in any community as a result of adopting the certification program. The proposed emission standards and certification program will ensure the deployment of only the cleanest DG equipment in all California communities.

TITLE 17. CALIFORNIA AIR RESOURCES BOARD

NOTICE OF PUBLIC HEARING TO CONSIDER THE ADOPTION OF A REGULATION TO ESTABLISH A DISTRIBUTED GENERATION CERTIFICATION PROGRAM AND A GUIDANCE FOR THE PERMITTING OF ELECTRICAL GENERATION TECHNOLOGIES

The Air Resources Board (the Board or ARB) will conduct a public hearing at the time and place noted below to consider adoption of a proposal to establish a distributed generation certification program and a proposed guidance for the permitting of electrical generation technologies by air pollution control and air quality management districts.

DATE: November 15, 2001

TIME: 9:00 a.m.

PLACE: California Environmental Protection Agency
Air Resources Board
Auditorium, Second Floor
1001 "I" Street
Sacramento, CA 95814

These items will be considered at a two-day meeting of the ARB, which will commence at 9:00 a.m. on Thursday, November 15, 2001, and may continue at 8:30 a.m., Friday, November 16, 2001. These items may not be considered until November 16, 2001. Please consult the agenda for the meeting, which will be available at least 10 days before November 15, 2001, and posted on the ARB website, to determine the day on which these items will be considered.

The facility is accessible to persons with disabilities. If accommodation is needed, please contact the ARB's Clerk of the Board by November 1, 2001, at (916) 322-5594, or Telecommunications Device for the Deaf (TDD) (916) 324-9531, or (800) 700-8326 for TDD calls from outside the Sacramento area, to ensure accommodation.

INFORMATIVE DIGEST OF PROPOSED ACTION AND POLICY STATEMENT OVERVIEW

Sections Affected: Proposed adoption of new sections 94200-94214, in article 3, subchapter 8, chapter 1, division 3 of title 17, California Code of Regulations (CCR).

Background

The California Distributed Generation Certification Program (Program), was established in California law by Senate Bill (SB) 1298 (chapter 741, statutes of 2000). SB 1298 focuses on electrical generation that is near the place of use, and defines these sources as "distributed generation" (DG). Therefore, electrical generation technologies that are subject to the proposed emission standards and certification program will be referred to hereafter as "Distributed Generation" or "DG" technologies in this notice.

The DG certification program created by SB 1298 is a new program and is codified in Health and Safety Code sections 41514.9 and 41514.10. This law requires the ARB to:

1. Adopt uniform emission standards for electrical generation technologies that are exempt from air pollution control or air quality management district (district) permit requirements;
2. establish a certification program for technologies subject to these standards; and
3. issue guidance to districts on the permitting or certification of electrical generation technologies subject to the district's regulatory jurisdiction.

The adoption of the certification program and uniform emission standards for electrical generation technologies that are exempt from air districts' permitting requirements is the subject of this rulemaking. The issuance of the guidance to the air districts on the permitting or certification of electrical generation technologies under their regulatory jurisdiction is a non-regulatory action.

SB 1298 mandates two levels of emissions standards for affected DG technologies. The law requires that the first set of standards become effective no later than January 1, 2003, and reflect the best performance achieved in practice by existing DG technologies that are exempt from district permitting requirements. The law also requires that, by the earliest practicable date, the final set of standards be made equivalent to the level determined by the ARB to be Best Available Control Technology (BACT) for permitted central station power plants in California. The emission standards must be expressed in pounds per megawatt hour (lbs/MW-hr) to reflect the efficiencies of various electrical generation technologies.

Description of the Proposed Regulatory Action

After January 1, 2003, new electrical generation units to be sold, leased or used in California, and that are exempt from district's permit requirements, must be certified by the ARB to defined emission standards. The ARB staff will assist the manufacturers with determining exemption levels for each district. If a proposed unit is subject to the district's permit requirements, it need not be certified by the ARB before it is sold, leased, or operated in that district. Equipment operating before January 1, 2003, will not be subject to the proposed standards.

The proposed regulatory action also includes labeling requirements, testing procedures, record keeping requirements, recertification requirements and payment of fees for technologies subject to the certification program. In accordance with Government Code sections 11345.3(c) and 11346.5(a)(11), the ARB's Executive Officer has found that the record keeping and reporting requirements of the proposed regulation are necessary for the health, safety, and welfare of the people of the State.

Lastly, the proposed regulatory action provides for the denial, suspension or revocation of certificates and creates an administrative appeals process for review of denials, suspensions or revocations of certificates issued under the program. The types of technologies that will be subject to the emission standards include microturbines, reformer-based fuel cells, small reciprocating engines, external combustion engines, or any combination thereof.

Description of the Proposed Non-Regulatory Action

SB 1298 specifies that the guidelines address BACT determinations for electrical generation technologies and, by the earliest practical date, shall make the determinations equivalent to the level determined by the ARB to be BACT for permitted central station power plants in California.

Comparable Federal Regulations

The certification program to be considered is not required by federal law or regulation. There are no comparable federal regulations covering emissions from the use of DG technologies.

Existing State Regulations

The certification program to be considered is a new program. There are no directly related laws or regulations. Staff reviewed existing state regulations governing portable equipment operation (Portable Equipment Registration Program) to ensure there were no conflicting provisions.

AVAILABILITY OF DOCUMENTS AND AGENCY CONTACT PERSONS

The ARB staff has prepared an initial statement of reasons (ISOR) for the proposed regulatory action, which includes a summary of the potential environmental and economic impacts of the proposal. The ISOR is entitled, "Staff Report: Initial Statement of Reasons for the Proposed Distributed Generation Certification Program." The ARB staff has also prepared a guidance document for the proposed non-regulatory action entitled, "Guidance for the Permitting for Electrical Generation Technologies."

Copies of the ISOR, the Guidance document, and the full text of the proposed regulation may be obtained from the Public Information Office, Air Resources Board, 1001 "I" Street, Environmental Services Center, 1st Floor, Sacramento, CA 95814, (916) 322-2990 at least 45 days prior to the scheduled hearing (November 15, 2001).

Upon its completion, the Final Statement of Reasons (FSOR) and the Guidance document will be available and copies may be requested from the agency contact persons in this notice, or may be accessed on the web site listed below.

Inquiries concerning the substance of the proposed regulatory action may be directed to the designated agency contact persons: Kitty Martin, Manager of the Program Assistance Section, Project Assessment Branch, Stationary Source Division at (916) 322-3907 and Marcelle Surovik, Air Pollution Specialist, Stationary Source Division at (916) 327-2951. Inquiries concerning the substance of the non-regulatory guidance document may be directed to Grant Chin, Air Resources Engineer, Stationary Source Division at (916) 327-5602.

Further, the agency representative and designated back-up contact persons to whom nonsubstantive inquiries concerning the proposed administrative action may be directed are Artavia Edwards, Manager, Board Administration & Regulatory Coordination Unit, (916) 322-6070, or Amy Whiting, Regulations Coordinator, (916) 322-6533. The Board has compiled a record for this rulemaking action, which includes all the information upon which the proposal is based. This material is available for inspection upon request to the contact persons.

If you are a person with a disability and desire to obtain this document in an alternative format, please contact the Air Resources Board ADA Coordinator at (916) 323-4916, or TDD (916) 324-9531, or (800) 700-8326 for TDD calls from outside the Sacramento area.

This notice, the ISOR and all subsequent regulatory documents, including the FSOR when completed, are available on the ARB Internet site for this rulemaking at http://www.arb.ca.gov/regact/dg01/dg01.htm. The Guidance document and all subsequent non-regulatory documents are available on the ARB Internet site at http://www.arb.ca.gov/energy/dg/dg.htm.

COSTS TO PUBLIC AGENCIES AND TO BUSINESSES AND PERSONS AFFECTED

The determinations of the Executive Officer of the ARB concerning the cost or savings necessarily incurred in reasonable compliance with the proposed regulatory action are presented below.

The ARB's Executive Officer has determined that the proposed regulatory action will not create costs, as defined in Government Code section 11346.5(a)(6), to other state agencies.

The Executive Officer has also determined that the proposed regulatory action will not create costs or savings in federal funding to the State; costs or mandate to any school district whether or not reimbursable by the State pursuant to part 7 (commencing with section 17500), division 4, title 2 of the Government Code; or non-discretionary savings to state or local agencies.

The proposed regulatory action will not impose a mandate upon and create costs to local agencies. Therefore, the Executive Officer has determined that the proposed regulatory action imposes no costs on local agencies that are required to be reimbursed by the state pursuant to part 7 (commencing with section 17500), division 4, title 2 of the Government Code, and does not impose a mandate on local agencies that is required to be reimbursed pursuant to Section 6 of Article XIII B of the California Constitution.

In developing this regulatory proposal, the ARB staff evaluated the potential economic impacts on manufacturers. The Executive Officer has initially assessed that the proposed regulatory action will have a minimal statewide adverse economic impact directly affecting businesses. The Executive Officer has also assessed that the proposed regulatory action will not have a statewide adverse economic impact directly affecting the ability of California businesses to compete with businesses in other states. The Board is not aware of any cost impacts that a representative private person or business would necessarily incur in reasonable compliance with the proposed action. In accordance with Government Code section 11346.3, the Executive Officer has determined that the proposed certification program should have minimal impacts on the creation or elimination of jobs within the State of California, minimal impacts on the creation of new businesses and the elimination of existing businesses within the State of California, and minimal impacts on the expansion of businesses currently doing business within the State of California. A detailed assessment of the economic impacts of the proposed certification program can be found in the ISOR.

The Board's Executive Officer has also determined that the regulation will affect a few small businesses.

Before taking final action on the proposed regulatory action, the ARB must determine that no reasonable alternative considered by the agency, or that has otherwise been identified and brought to the attention of the agency, would be more effective in carrying out the purpose for which the action is proposed or would be as effective and less burdensome to affected private persons or businesses than the proposed action.

SUBMITTAL OF COMMENTS

The public may present comments relating to this matter orally or in writing at the hearing, and in writing or by e-mail before the hearing. To be considered by the Board, written submissions not physically submitted at the hearing must be received **no later than 12:00 noon, November 14, 2001**, and addressed to the following:

Postal mail is to be sent to:

Clerk of the Board
Air Resources Board
1001 "I" Street, 23rd Floor
Sacramento, California 95814

Electronic mail is to be sent to: dg01@listserv.arb.ca.gov and received at the ARB **no later than 12:00 noon, November 14, 2001.**

Facsimile submissions are to be transmitted to the Clerk of the Board at (916) 322-3928 and received at the ARB **no later than 12:00 noon, November 14, 2001**.

The Board requests but does not require 30 copies of any written submission. Also the ARB requests that written, facsimile, and e-mail statements be filed at least 10 days prior to the hearing so that ARB staff and Board Members have time to fully consider each comment. The ARB encourages members of the public to bring to the attention of staff in advance of the hearing any suggestions for modification of the proposed regulatory action.

STATUTORY AUTHORITY AND REFERENCE

These regulatory and non-regulatory actions are proposed under the authority granted to the ARB in the Health and Safety Code sections 39600, 39601, 39605, 41514.9 and 41514.10. These actions are proposed to implement, interpret, or make specific, Health and Safety Code sections 41514.9 and 41514.10.

HEARING PROCEDURES

The public hearing will be conducted in accordance with the California Administrative Procedure Act, title 2, division 3, part 1, chapter 3.5 (commencing with section 11340) of the Government Code. Following the public hearing, the ARB may adopt the regulatory language as originally proposed or with nonsubstantial or grammatical modifications. The ARB may also adopt the proposed regulatory language with other modifications if the text as modified is sufficiently related to the originally proposed text that the public was adequately placed on notice that the regulatory language as modified could result from the proposed regulatory action. Modifications may include, but are not limited to, modifying the RAFs for alternative fuel vehicles. In the event that such modifications are made, the full regulatory text, with the modifications clearly indicated, will be made available to the public for written comment at least 15 days before it is adopted. The public may request a copy of the modified regulatory text from the ARB's Public Information Office, Environmental Services Center, 1001 "I" Street, First Floor, Sacramento, California 95814, (916) 322-2990.

CALIFORNIA AIR RESOURCES BOARD

Michael P. Kenny
Executive Officer

Date: September 18, 2001

"The energy challenge facing California is real. Every Californian needs to take immediate action to reduce energy consumption. For a list of simple ways you can reduce demand and cut your energy costs, see our Web-site at www.arb.ca.gov."

California Environmental Protection Agency
AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR THE PROPOSAL TO ESTABLISH A DISTRIBUTED GENERATION CERTIFICATION PROGRAM

Stationary Source Division
Project Assessment Branch

Release Date:
September 28, 2001

State of California
AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR PROPOSED RULEMAKING

Public Hearing to Consider

ADOPTION OF THE PROPOSAL TO ESTABLISH A DISTRIBUTED GENERATION CERTIFICATION PROGRAM

To be considered by the Air Resources Board on November 15, 2001, at:

California Environmental Protection Agency
Headquarters Building
1001 I Street
Sacramento, California

State of California
AIR RESOURCES BOARD

PROPOSED REGULATION TO ESTABLISH A DISTRIBUTED GENERATION CERTIFICATION PROGRAM

Executive Summary and Technical Support Document

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September 2001

Staff Report: Initial Statement of Reasons for the Proposed Distributed Generation Certification Program

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State of California
AIR RESOURCES BOARD

Staff Report: Initial Statement of Reasons for the Proposed Distributed Generation Certification Program

Executive Summary

I. INTRODUCTION

This executive summary presents the Air Resources Board (ARB or Board) staff's proposal for establishing a certification program that includes emission standards for electrical generation technologies, as required by SB 1298.

Senate Bill 1298 (SB 1298), which was chaptered on September 27, 2000, requires the ARB to adopt uniform emission standards for electrical generation technologies that are exempt from air pollution control or air quality management districts' (districts) permit requirements. The statute also directs the ARB to establish a certification program for technologies subject to these standards. SB 1298 focuses on electrical generation that is near the place of use, and defines these sources as "distributed generation" (DG). Therefore, electrical generation technologies that are subject to the proposed emission standards and certification program will be referred to hereafter as "distributed generation" or "DG" technologies in this report.

SB 1298 requires the ARB to:

1) Adopt a certification program and uniform emission standards for electrical generation technologies that are exempt from air districts' permitting requirements; and

2) Issue guidance to the air districts on the permitting or certification of electrical generation technologies under their regulatory jurisdiction.

SB 1298 mandates two levels of emission standards for affected DG technologies. The law requires that the first set of standards be effective no later than January 1, 2003, and reflect the best performance achieved in practice by existing DG technologies that are exempt from district permits. The law also requires that, by the earliest practicable date, the standards be made equivalent to the level determined by the ARB to be the best available control technology (BACT) for permitted central station power plants in California. The emission standards must be expressed in pounds per megawatt hour (lb/MW-hr) to reflect the efficiencies of various electrical generation technologies.

This report will discuss only the ARB staff's proposed certification program for DG technologies that are exempt from districts' permitting requirements. The district guidance is presented in a separate ARB report entitled Guidance for the Permitting of Electrical Generation.

This executive summary provides an overview of the development of the DG Certification Regulation, a summary of the ARB staff's recommendations, and a brief discussion of the environmental and economic impacts resulting from the proposal. Volume II of this report, the Technical Support Document, provides a more detailed presentation of the technical basis for the proposed DG certification requirements.

II. BACKGROUND

1. What is the purpose of SB 1298?

Some businesses are expected to consider supplementing or replacing electricity from central station power plants with distributed generation sources that are near the place of use. On an equivalent energy production basis (i.e. pounds of air pollutant per kilowatt-hour of electricity produced), DG emissions can be an order of magnitude higher than emissions from central station power plants. If more businesses employ DG technologies, the emissions from these sources could have a negative impact on air quality and public health in California. DG sources are located near the place of consumption and can have a localized impact on public health. SB 1298 requires that each DG unit is either certified by the ARB for use or subject to the permitting authority of a district. Developing uniform emission standards for DG technologies will ensure the deployment of only the cleanest DG equipment in California.

III. PUBLIC OUTREACH

The ARB staff's proposal was developed in a public process that involved all affected parties. The ARB staff held five public consultation meetings throughout the State during the development of the DG certification program to solicit ideas and comments on proposed certification requirements and emission levels. A DG workgroup was formed to assist the ARB staff with identifying and resolving issues during the development of the DG program. The workgroup, comprised of over 90 representatives of affected industry, environmental groups and district staff, met six times between January and June 2001, in Sacramento.

Information about the proposed DG program was distributed at community meetings as part of the ARB's Children's Environmental Health and Environmental Justice programs.

An e-mail list server was created to notify potentially affected industry and other interested parties of the progress of the ARB's DG certification program. Approximately 700 individuals from federal, state, and local government, environmental groups, and industry subscribe to the list server. The ARB staff created and has maintained a website to facilitate the dissemination of up-to-date information of the progress of the DG program at *http://www.arb.ca.gov/energy/dg/dg.htm.*

In addition to the workgroup meetings and public consultation meetings, the ARB staff met numerous times, face-to-face and by phone, with stakeholders to discuss specific issues of interest.

The ARB staff apprised the air districts and the United States Environmental Protection Agency (U.S. EPA) of the DG certification activities through the workgroup meetings and California Air Pollution Control Officer's Association's (CAPCOA) Engineering Managers Committee meetings. The ARB staff also held several conference calls with district staff to obtain the districts' perspectives on the ARB staff's proposed DG program.

IV. OVERVIEW OF DG TECHNOLOGIES

1. <u>What types of sources are subject to the DG certification program?</u>

The DG technologies that are exempt from district permitting requirements are subject to the certification program. Stationary DG sources fall under the districts' authority but districts have chosen to exempt many of these units from permits or other control requirements. The ARB staff reviewed the exemption levels in each of California's 35 air district rules to determine what types of technologies are generally not permitted by the air districts. Exemption levels vary among California's 35 air districts. Some examples of technologies that will most likely be subject to the DG certification program and emission standards are microturbines, small reciprocating engines, external combustion engines, and fuel cells. Engines that are exempt from district permit requirements are smaller units, such as those with less than a 100 horsepower rating. Microturbines exempt from district permits are typically 30 kw to 70 kw in size.

2. <u>What are the uses of DG technologies?</u>

Many smaller DG technologies are just now entering the market, making it difficult to predict their future uses. It is likely that most DG technologies will be used to supplement electricity that is supplied by the grid. However, the installed cost per kilowatt for most DG technologies are generally much higher than the installed cost/kw for central station power plants. For example, an average installed cost/kw for a central station power plant is $510 while the installed cost/kw for a microturbine can be up to $1,500.

DG technologies can be integrated into combined heat and power (CHP) packages where the waste heat from the combustion process is used for heating water or for chilling purposes. DG units that are integrated with CHP are more cost attractive than DG units that produce power only. For this reason, DG technologies that include CHP packages are likely to be most attractive to users that also have a use for the heat provided.

A few unpermitted DG technologies are currently operating in California. Most of these units are at research facilities or at local utility districts where applicability and reliability are being evaluated. The uncertainty in the future cost and reliability of electricity in California makes it difficult to project future sales of DG technologies. However, DG equipment manufacturers claim that they will experience increased sales over the next few years.

3. <u>How were emission standards determined for DG technologies?</u>

SB 1298 requires the ARB to establish at least two levels of emission standards for DG technologies that are exempt from air district permit requirements. The first level must reflect the best performance achieved in practice by existing DG technologies and must become effective no later than January 1, 2003. By the earliest practicable date, the standards must be made equivalent to the level determined by the ARB to be the best available control technology for permitted central station power plants.

In order to establish emission standards for DG technologies, test data were needed for these sources. Although source testing had been conducted on some microturbines at a research center at University of California at Irvine and through the Electric Power Research Institute (EPRI), this data was not publicly available. Consequently, early in the regulatory development process, the ARB staff requested any available source test data from potentially affected manufacturers to help staff identify the lowest achievable emission levels from these technologies. The ARB staff received data from five manufacturers. The ARB staff also conducted a source test on a microturbine located at an electric utility office in Sacramento and used the results to confirm the manufacturers' test data.

In order to develop the second required set of emission standards, the ARB staff analyzed BACT determinations for central station power plants in California. The ARB staff used data included in the 1999 ARB report entitled <u>Guidance for Power Plant Siting and Best Available Control Technology</u>. The report includes BACT determinations for central station power plants that generate 50 megawatts or greater of electricity. The ARB staff reviewed the BACT determination in this report for combined-cycle gas turbines, which is the configuration used in all new central station power plants. The BACT determinations were converted to an equivalent lb/MW-hr emission standard with an adjustment for a ten percent total system (transmission and distribution system) average line loss factor.

4. How were the compliance dates determined?

SB 1298 requires new DG technologies to meet the lowest achievable emission standards that reflect the best performance achieved in practice by existing DG technologies, commencing January 1, 2003. The law also requires that these technologies meet the emission limits of central station power plants by the earliest practicable date. To determine a reasonable compliance date for DG technologies to meet central station BACT levels, the ARB staff surveyed manufacturers regarding how long it would take to achieve these levels. Manufacturers indicated to the ARB staff that it would take a minimum of four years to develop a new product. A 2007 compliance date was chosen to give manufacturers a five year lead time (from the time the certification program is approved by the Board) to develop a technology that can meet the SB 1298-mandated standards equivalent to central station power plants. To assist manufacturers with meeting these standards, the ARB staff included provisions for calculating a credit for highly efficient CHP packages that are integrated with DG technologies.

V. SUMMARY OF THE PROPOSED DG CERTIFICATION PROGRAM

1. What does the proposed DG certification program require?

After January 1, 2003, manufacturers of new electrical generation units that are exempt from district permit requirements must have their equipment certified by the ARB to the proposed emission standards. There are 35 air districts in California. The ARB staff will assist the manufacturers with determining exemption levels for each district. If a proposed unit is not subject to the district's permit requirements, it must be certified by the ARB before it can be sold, leased, or operated in that district. Equipment operating before January 1, 2003 will not be subject to the proposed standards. Certifications are valid for four years or until January 1, 2007.

The ARB staff is proposing two sets of emission standards for oxides of nitrogen (NOx), carbon monoxide (CO), volatile organic compounds (VOCs), as defined by ARB Test Method 100, and particulate matter (PM). As was previously mentioned, the first set of standards is effective on January 1, 2003, and the second set of standards becomes effective on January 1, 2007. DG technologies must be able to maintain the emission standards levels that they are certified to for 15,000 hours. The 15,000 hours requirement is within the expected useful life of nonselective catalytic reduction units that may be integrated with some technologies (i.e. reciprocating engines) seeking certification and is also within many manufacturers' warranty periods. A summary of the emission standards for 2003 is included in Table I.

Table I -2003 Emission Standards (lb/MW-hr)

Pollutant	DG Unit not Integrated with Combined Heat and Power	DG Unit Integrated With Combined Heat and Power
Oxides of Nitrogen (NO_x)	0.5	0.7
Carbon Monoxide (CO)	6.0	6.0
Volatile Organic Compounds (VOCs)	1.0	1.0
Particulate Matter (PM)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain per 100 standard cubic feet (scf)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain per 100 standard cubic feet (scf)

Emission standards have been set for DG units that are not integrated with combined heat and power packages and for DG units that are integrated with combined heat and power packages. DG units that are certified without integrated CHP must meet the more stringent standard. These standards are based on achievable limits that were determined from the ARB staff's review of DG manufacturers' emissions data. DG units that are certified with integrated CHP are given an emission credit that is reflected in a slightly higher emission standard value. The emission credit is equivalent to the emissions from a boiler that would otherwise be used to produce the process heat coming from the DG unit. These standards provide recognition of the emissions benefits of CHP applications.

A manufacturer can use an energy credit for meeting either set of emission standards if the DG unit is integrated and certified with a zero emission technology including, but not limited to, a photovoltaic cell, wind turbine, non-reformer fuel cell, or Stirling-cycle engine that uses waste heat or solar energy. The electrical output of the zero emission technology can be added to the electrical output of the DG unit subject to certification to calculate the lb/MW-hr emission rate of the integrated package. This credit provides recognition of the emissions benefit of zero emission technologies.

A summary of the 2007 emission standards is included in Table II.

Table II-2007 Emission Standards (lb/MW-hr)

Pollutant	Emission Standard
Oxides of Nitrogen (NO_x)	0.07
Carbon Monoxide (CO)	0.10
Volatile Organic Compounds (VOCs)	0.02
Particulate Matter (PM)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain per 100 scf

As was mentioned earlier, the 2007 standards are based on the 1999 BACT determinations for central station power plants adjusted for a total system average line loss factor of ten percent. Manufacturers of DG technologies that are integrated with highly efficient CHP will be able to calculate an energy credit for usable process heat. This credit can be used to meet the 2007 standards.

To assist zero emission technologies to enter the California market, provisions are also included to allow zero emission technologies to seek voluntary certification. It is expected that manufacturers of these technologies may seek voluntary ARB certification for marketing purposes.

2. Are there exemptions to the certification requirements?

Certain technologies are exempt from certification requirements. A technology does not have to be certified if it does not emit an air contaminant. An electrical generation technology does not have to be certified if it is registered under the ARB's Portable Equipment Registration Program. In addition, certification is not required if an electrical generation technology will only be used when electrical or natural gas service fails or for emergency pumping of water for fire protection or flood relief.

3. What is the application process?

Manufacturers seeking certification will submit an application package to the ARB for review. The following information must be included in the application for the ARB to determine eligibility for certification:

- Name of the applicant and contact information;
- a description of the DG unit and model number;
- maximum output rating;
- fuel for which certification is being sought;
- any air pollution control equipment that is integrated with the technology; and

- emissions test data, supporting calculations, quality control/assurance information, and all other information needed to demonstrate compliance with the emission standards and durability requirements.

Upon finding that the DG technology meets the requirements for certification, an Executive Order of Certification will be issued by the ARB. The Executive Order will describe the DG unit and indicate if the unit was certified with an integrated CHP package, zero emission technology, and/or air pollution control equipment. The Executive Order will also indicate that the certification is required only in those districts where the specific DG unit is exempt from district permit requirements.

4. What are the testing requirements?

Manufacturers must include a source test report with their applications for certification demonstrating that their equipment meets the emission limits. ARB test methods, or alternative approved procedures must be used. Specific testing parameters are included in the certification requirements. Before commercial operation, each DG unit manufactured for sale, lease, or use in California must be monitored for NOx emissions using an approved NOx screening device. The monitoring information will be used by the ARB staff at a later date as part of a quality control review of the emission test data.

5. What are the certification fees?

To recover costs incurred by the ARB staff to process a request for DG certification, a $2,500 application fee will be due at the time an application package is submitted. Technologies seeking a recertification (every four years) will be assessed a $2,500 fee. To provide an economic incentive for the cleanest DG technologies, DG units that can meet the 2007 standard by 2003 will not be assessed a fee for the 2003 standard certification. For the same reason, zero emission technologies that are seeking voluntary certification will not be assessed a fee.

6. Will there be another review of electrical generation technologies?

To address the inherent uncertainties associated with emerging technologies, the ARB staff will conduct another review of DG technologies and report the findings to the Board by July 2005. This will give manufacturers and the ARB staff two and a half years after the first set of standards are in place to evaluate information on the performance and capabilities of DG technologies as well as evaluate DG deployment in California. The review will address newly available emissions data, source testing procedures, operating conditions, operational modes, reliability, and emissions durability for these technologies.

The review will also include an evaluation of any new BACT determinations for central station power plants and an evaluation of any control measures under development or recently-adopted by the ARB that could have a bearing on the 2007 standard.

7. Are there other requirements in the proposal?

The proposed certification regulation also contains provisions addressing recordkeeping, labeling requirements, recertification requirements, and enforcement.

8. What are the key unresolved issues?

While ARB staff has been able to resolve the majority of concerns raised by manufacturers and environmental groups, there are some issues for which general consensus has not been reached.

Some manufacturers and environmental groups do not believe that electrical generation technology used for emergency purposes only should be exempt from the certification requirements. These units, which provide essential electricity during loss of electrical or natural gas services, are generally run on diesel fuel and subject to district permit requirements. The proposed emission standards in the certification program essentially eliminate diesel-fueled engines from being eligible for certification. The ARB staff is now evaluating control measures for diesel PM and expects to present a proposed control measure for diesel-fueled engines to the Board next year.

Some manufacturers and environmental groups do not believe that DG units should be exempt from the certification requirements if they are registered under the ARB's Portable Equipment Registration Program (PERP), because the emission limits in the PERP are higher than the proposed limits in the certification program. The ARB staff does not anticipate many units subject to the certificate requirements to fall under the definition of portable equipment. The ARB staff is currently considering changes to the PERP, including modifying emission limits, and anticipates presenting amendments to the Board next year.

Some industry sources believe that the 2007 compliance date by which DG units must meet central station power plant emission levels is too stringent. Manufacturers indicated to ARB staff that is would take four years to research and develop a new product. A 2007 compliance date was chosen to give manufacturers a five year lead time (from the time the certification program is approved by the Board) to develop a technology that can meet the central station power plant BACT levels.

VI. IMPACTS OF THE PROPOSED CERTIFICATION PROGRAM – HEALTH, ENVIRONMENTAL, ECONOMIC

1. Are there any health impacts as a result of the certification program?

The DG certification program will ensure that distributed generation is deployed in a way that avoids a negative effect on air quality and public health. If uncontrolled, emissions from DG technologies could negatively impact air quality and public health. Setting state-of-the-art emission standards now for emerging DG technologies will help protect California citizens from these new sources of air emissions.

2. Are there any significant adverse environmental impacts associated with the proposed certification program?

The ARB is committed to evaluating community impacts of proposed measures, including environmental justice concerns. The proposed certification program is not expected to result in significant negative environmental impacts in any community. The result of the proposed certification program will be reduced exposures to small sources of electrical generation for all communities.

3. Are there any significant adverse economic impacts associated with the proposed certification program?

Manufacturers' efforts to comply with the 2003 emission standards are not expected to result in any significant adverse economic impacts. Affected manufacturers have indicated to the ARB staff that they expect their technologies to meet the 2003 emission standards by January 1, 2003. However, there will be an economic impact on some manufacturers with meeting the 2007 standard. These manufacturers have indicated that they will incur research and development costs to redesign their technologies to meet the 2007 standards which could also result in higher product cost. Manufacturers have indicated that it may cost several million dollars to accomplish its redesign. The ARB staff is also aware that it will be difficult for some DG technologies such as reciprocating engines to ever meet BACT levels for central station power plants, regardless of compliance dates, because of the prohibitive cost of additional emission control devices that would be needed to meet the standards. However, these manufacturers can use an energy credit if they sell their products integrated with CHP packages. With this credit, fewer additional controls would be needed to allow the DG unit to meet the 2007 standard.

The overall statewide cost of the proposed certification program for the 2003 standards is estimated to be $370,000 with an estimated individual business cost of $11,000 to $21,500.

Some technologies may not initially or may never meet the emission standards, which may delay availability or reduce product choices. This could potentially increase the price of DG technologies. Also products may increase in price when manufacturers redesign their products to meet the 2007 standards. To offset these possibilities, the ARB staff's proposal provides credits for CHP and zero emission technology packages to enable manufacturers to remain competitive and still meet the emission standards established by SB 1298.

VII. NEXT STEPS

If the proposed certification program is approved, the ARB staff must implement and enforce the certification program. The ARB staff will conduct outreach to educate stakeholders on the certification program. While waiting for the California Office of Administrative Law (OAL) to approve the DG certification program, the ARB staff will process a limited number of voluntary pilot certifications for manufacturers. These pilot certifications will provide manufacturers with an opportunity to request an early provisional certification of their DG technology unit that is conditional upon final OAL approval of the program. Finally, the ARB staff will complete an electrical generation technology review and report the findings to the Board by July 2005.

VIII. RECOMMENDATION

The ARB staff recommends that the Board approve the proposed certification requirements and emission standards for DG technologies. The proposal addresses the requirements in the statute, public health protection, and the impacts on industry and presents the most reasonable approach to meeting the mandates of SB 1298.

State of California
AIR RESOURCES BOARD

Staff Report: Initial Statement of Reasons for the Proposed Distributed Generation Certification Program

Volume II: Technical Support Document

I. INTRODUCTION

A. Overview

Senate Bill 1298 (SB 1298), which was chaptered on September 27, 2000, requires the ARB to adopt uniform emission standards for electrical generation technologies that are exempt from air pollution control or air quality management districts' (districts) permit requirements. The statute also directs the ARB to establish a certification program for technologies subject to these standards. A copy of the SB 1298 legislation is included in Appendix A.

SB 1298 focuses on electrical generation that is near the place of use, and defines these sources as "distributed generation." Thus, electrical generation technologies that are subject to the proposed emission standards and certification program will be hereafter referred to as "distributed generation" or "DG" technologies in this technical report.

Exemption levels vary among California's 35 air districts. Some examples of technologies that will most likely be subject to the DG certification program and emission standards are microturbines, small reciprocating engines, external combustion engines, and fuel cells. Engines that are exempt from district permit requirements are smaller units, such as those with less than a 100 horsepower. Microturbines exempt from district permits are typically 30 kw to 70 kw in size.

SB 1298 mandates that the ARB establish at least two levels of emission standards for affected DG technologies. The law requires that the first set of standards be effective no later than January 1, 2003, and reflect the best performance achieved in practice by existing DG technologies that are exempt from district permits. The law also requires that, by the earliest practicable date, the standards be made equivalent to the level determined by the ARB to be the best available control technology (BACT) for permitted central station power plants in California. The emission standards must be expressed in pounds per megawatt hour (lb/MW-hr) to reflect the efficiencies of various electrical generation technologies.

In addition to developing the certification program, the ARB is required to issue guidance to the air districts on the permitting or certification of electrical generation technologies that are under their regulatory jurisdiction. The guidance shall address BACT determinations for these technologies. As is required in the certification program, these BACT determinations must, by the earliest practicable date, be made equivalent to the level determined by the ARB to be BACT for permitted central station power plants in California. The non-regulatory district guidance, Guidance for the Permitting of Electrical Generation Technologies, is not part of this Initial Statement of Reasons. However, it is important to note that the ARB staff is proposing comparable emission levels, where applicable, for both the district guidance and the proposed DG certification program.

B. Purpose of Legislation

Some businesses are expected to consider supplementing or replacing electricity from central station power plants with distributed generation sources that are near the place of use. On an equivalent energy production basis (i.e. pounds of air pollutant per megawatt-hour of electricity produced), emissions from some DG technologies can be an order of magnitude higher than emissions from central station power plants.

If more businesses employ DG technologies, the emissions from these sources could have a negative impact on air quality and public health in California. SB 1298 requires that each DG unit is certified by the ARB for use or subject to the permitting authority of a district. Developing uniform emission standards for DG technologies will ensure the deployment of only the cleanest DG equipment in California.

In response to SB 1298, the ARB staff is proposing requirements for a DG certification program that include proposed emission standards. The ARB staff's proposal is included in Appendix B. The remainder of this technical report will discuss the public input process during the development of the proposed certification program; provide an overview of DG technologies and emissions from electrical generation technologies; discuss the specific requirements of the proposed certification program; and discuss the public health, economic and environmental impacts of the ARB staff's proposal.

II. PUBLIC OUTREACH

This chapter contains a summary of the ARB staff's efforts to communicate with all affected parties in a public process during the development of the proposed DG certification program. During the development of the proposed DG certification program, the ARB staff met numerous times with electrical generation technology manufacturers, environmental groups, representatives of DG technology users, and air district staff to discuss potential certification requirements and emission standards. In addition, the ARB staff also communicated with staff from other state air quality agencies that are developing DG programs.

A. General Public Involvement

A little more than a month after SB 1298 was chaptered by the California Secretary of State, the ARB staff held a public consultation meeting to discuss the requirements in SB 1298 and to solicit ideas on the general direction that the ARB staff should take to develop the required DG certification program. Questions were developed in advance of the workshop for consideration by potential stakeholders. The questions addressed applicability, potentially affected technologies, the certification process, and possible components of the district guidance. At this November 8, 2000, public consultation meeting, stakeholders were given the opportunity to present their suggestions for implementing the DG certification program.

Four additional public consultation meetings were held in July 2001 on the ARB staff's proposed draft certification regulation. The first was held July 11, 2001 in Sacramento. The second was held in Diamond Bar (Los Angeles area) on July 17, 2001. The third was held on July 18, 2001 in San Francisco, and the last was held on July 19, 2001 in Fresno. An overview of the draft certification program was presented by the ARB staff at each of the consultation meetings prior to inviting discussion and comment by the stakeholders.

The ARB staff created and has maintained a website to facilitate the dissemination of up-to-date information on the progress of the DG program at *http://www.arb.ca.gov/energy/dg/dg.htm*. An e-mail list server was also created to notify potentially affected industry and other interested parties of the ARB staff's progress in developing the DG certification program. Approximately 700 individuals from federal, state, and local government; environmental groups; and industry subscribe to the list server. A DG fact sheet in English and Spanish was made available at various community meetings held by the ARB. These meetings were conducted as part of the ARB's Children's Environmental Health and Environmental Justice programs.

B. Industry Involvement

A workgroup was formed in January 2001 to assist the ARB staff with developing a certification program. The workgroup consisted of approximately 90 individuals representing manufacturers of microturbines, engines, fuel cells and other DG technologies; environmental groups; the California Energy Commission; the California Public Utilities Commission; utility companies; the United States Environmental Protection Agency (U.S. EPA); local air districts; and other interested parties. The first workgroup meeting was held on January 29, 2001, in Sacramento. Subcommittees were created at this meeting to address specific issues associated with developing a DG certification program. The subcommittees met at the ARB offices on February 15, March 6, and March 27, 2001. Workgroup meetings were held again on May 1 and June 4, 2001 to discuss draft versions of the DG certification requirements. Following the workgroup and public consultation meetings, staff revised the draft DG certification requirements to reflect consideration of the verbal and written comments received.

In addition to the workgroup and public consultation meetings, staff met numerous times, face-to-face and by phone, with industry representatives to discuss and resolve issues specific to that industry. During the development of the proposed certification program, the ARB staff held over 15 meetings with individual industry groups and had over 100 telephone calls with industry representatives.

C. Government Agency Involvement

During the development of the DG program, the ARB staff apprised the air districts and U.S. EPA of the DG certification activities through the California Air Pollution Control Officer's Association's (CAPCOA) Engineering Managers Committee meetings. Representatives from some of these agencies were also members of the ARB's DG workgroup. The ARB staff also held several conference calls with district staff to obtain the districts' perspective on the ARB staff's proposed DG program.

The Texas Natural Resource Conservation Commission (NRCC) issued a new standard air permit for electric generating units in May 2001. The ARB staff reviewed the new Texas permit rule and communicated with staff from the Texas NRCC during the development of ARB's proposed DG certification program.

The ARB staff has also been participating in the Distributed Generation Emissions Collaborative Working Group. The Working Group includes representatives from various state public utility commissions, other state air quality programs, manufacturers, and the National Resources Defense Council. The Working Group's activities are organized and coordinated by the Regulatory Assistance Project, a non-profit organization that provides workshops and education assistance to state public utility regulators on electric utility regulation. The goal of the Working Group is to develop a national model rule for emissions from DG technologies by the fall of 2001.

D. Issues

While the ARB staff has been able to resolve the majority of concerns raised by manufacturers and environmental groups during the development of the certification program, there are some issues for which general consensus has not been reached.

Some manufacturers and environmental groups do not believe that electrical generation technology used for emergency purposes only should be exempt from the certification requirements. These units, which provide essential electricity during loss of electrical or natural gas services, are generally run on diesel fuel and subject to district permit requirements that restrict the number of hours per year the unit can run. The proposed emission standards in the certification program are at levels that essentially eliminate diesel-fueled engines from being eligible for certification. The ARB staff currently has a program to address sources of diesel emissions. The ARB staff identified particulate matter (PM) from diesel-fueled engines as a toxic air contaminant in 1998. Last year, the ARB staff evaluated possible risk reduction measures for diesel PM emissions and presented its finding in a report entitled <u>Risk Reduction Plan to Reduce Particulate Matter Emission from Diesel-Fueled Engines and Vehicles</u>. The ARB staff is now evaluating control measures for diesel PM and expects to present a proposed control measure for diesel-fueled engines to the Board next year.

Some manufacturers and environmental groups do not believe that DG units should be exempt from the certification requirements if they are registered under the ARB's Portable Equipment Registration Program (PERP), because the emission limits in the PERP are higher than the proposed limits in the certification program. The ARB staff does not anticipate many units subject to the certificate requirements to fall under the definition of portable equipment. Portable equipment can be used no more than one year and a day at one location. The ARB staff is currently considering changes to the PERP, including modifying emission limits, and anticipates presenting amendments to the Board next year.

Some industry sources believe that the 2007 compliance date by which DG units must meet central station power plant emission levels is too stringent. Some sources suggested moving the compliance date to 2010 or later. SB 1298 requires DG technologies to meet central station BACT levels at the earliest practicably date. Manufacturers indicated to ARB staff that is would take four years to research and develop a new product. A 2007 compliance date was chosen to give manufacturers a five year lead time (from the time the certification program is approved by the Board) to develop a technology that can meet the central station power plant BACT levels. Manufacturers can calculate a credit for highly efficient CHP packages that are integrated with DG units. With this credit, fewer additional controls and product design would be needed to allow the DG unit to meet the 2007 standard.

III. OVERVIEW OF DG TECHNOLOGIES

This chapter provides an overview of DG technologies that are most likely to be affected by the proposed certification program. The overview includes a discussion of the types of DG technologies, their possible uses, and the number of units operating in California.

A. Descriptions of DG Technologies

Electrical generation technologies that are exempt from districts' permit requirements will be subject to the ARB's certification program. Stationary DG sources fall under the districts' authority but districts have chosen to exempt many of these units from permits or other control requirements. The ARB staff reviewed the exemption levels in each of California's 35 air district rules to determine what types of technologies are generally not permitted by the air districts. A summary of district exemptions is included in Appendix C. Unpermitted DG technologies include fossil-fueled and zero emission technologies. The fossil-fueled technologies include microturbines, fuel cells, reciprocating engines, and external combustion engines. Zero emission technologies include, but are not limited to, wind turbines, photovoltaic cells, external combustion engines that use only waste heat or solar energy, and some fuel cells. Some DG technologies, such as fuel cells and external combustion engines, can fall under both categories.

1. Microturbines

Microturbines are high-speed, single-rotor turbines that are generally less than 100 kilowatts (kw) in size and usually burn natural gas. They can operate alone or in parallel with a number of units.

2. Fuel Cells

A fuel cell is an electrochemical device that combines hydrogen with oxygen to produce electricity, heat, and water. A fuel cell consists of an anode, cathode, and electrolyte. Electrochemical oxidation and reduction reactions take place at the electrodes to produce electrical current. Each individual fuel cell produces less than one volt, so cells are stacked to obtain the desired voltage. There are four types of fuel cells: phosphoric acid, molten carbonate, solid oxide, and proton exchange membrane. The hydrogen fuel can be supplied through a hydrogen tank or with a reformer that extracts the hydrogen from a fossil fuel such as methane or natural gas. Fuel cells that use a reformer to create their hydrogen source can emit small quantities of air pollutants.

3. Reciprocating Engines

Reciprocating engines generate power from the combustion of an air/fuel mixture. The combusted mixture provides rotational energy to drive equipment such as an electrical generator.

4. External Combustion Engines (Stirling-cycle engines)

A Stirling-cycle engine is a closed loop engine where heat is provided outside the engine to move a piston. The heat can be from any source such as waste heat, solar energy, or combustion gases.

5. Zero Emission Technologies

Zero emission technologies have no air emissions. They include, but are not limited to, wind turbines, photovoltaics, external combustion engines that use only waste heat or solar energy, and non-reformer fuel cells.

Wind turbines: Wind turbines generate electricity when wind passes by blades that are mounted on a rotating shaft. As the wind moves the blades, the rotation of the blades turns a generator that produces electricity.

Photovoltaics: Photovoltaics directly convert sunlight into electricity through the use of solar cells, which are grouped together to form a panel. The panels can be grouped together to produce the desired voltage.

B. Uses of DG Technologies

Most smaller (70 kw and below) DG technologies are just now entering the market, making it difficult to predict their future uses. It is likely that most DG technologies will be used to supplement electricity that is supplied by the grid. However, the cost per kilowatt for producing electricity from DG units is generally much higher than the cost of electricity supplied from the grid. Integrated DG units with combined heat and power (CHP) packages can make the cost of DG technologies more competitive with the grid. In a CHP package, the waste heat from the combustion process or the electrochemical reaction (such as in a fuel cell) is captured and used for heating water or for chilling purposes. In areas where the cost of electricity from the grid is high, CHP packages are an even more attractive option. For this reason, future sales of DG technologies in California are expected to include CHP packages.

The smaller DG technologies are just now entering the commercialization stage. To date, manufacturers have placed their DG units primarily at research facilities and at local utility districts in California. The units have been placed at these sites primarily to demonstrate applicability and reliability. Most new proposals for DG technologies include single DG units with CHP packages, although some proposals do include clustering of several units that can provide hundreds of kilowatts of electricity output. In some situations, the DG manufacturer can secure natural gas contracts for their customers with prices that are lower than their existing commercial rates. This decrease allows the cost of securing DG technology supplied electricity to be more competitive with grid supplied electricity.

The future electricity market in California is uncertain making it difficult to project future sales and use of DG technologies. However, manufacturers of DG technologies claim that they will experience increased sales over the next few years.

To provide a better understanding of potential DG uses in California, a comparison of the purchase and installation cost per kilowatt output (installed cost/kw) for typical DG technologies and a central station power plant is included in Table 1. The table indicates that the installed cost of DG technologies is higher than that of central station power plants. Of course, as more technologies are manufactured and sold over the next few years, the cost/kw of DG technologies would be expected to decrease. For now, adding CHP packages to DG units makes purchasing and using DG technologies more attractive especially in areas where the cost of electricity from the grid is high.

Table 1-Installed Cost per Kilowatt of Electrical Generation Technologies

Technology	Installed Cost/kilowatt
Central Station Power Plant	$510
Natural Gas Internal Combustion Engines	$600
External Combustion (Stirling-cycle) Engines	$1000
Microturbines	$1000-1500
Wind	$1000-4000
Solar	$2500-8000
Fuel Cells	$4000-4500

C. Inventory of DG Technologies

Individual unpermitted sources are not included in the district inventories or in the statewide emissions inventory that is maintained by the ARB.

Consequently, the ARB staff relied on conversations with manufacturers to determine how many unpermitted DG technologies are operating in California and where they are located.

The ARB staff has identified 25 potentially affected DG technology manufacturers that are at various stages of commercialization. The manufacturers include: 16 fuel cell manufacturers; 4 microturbine manufacturers; two reciprocating engine (without CHP packages) manufacturers; two reciprocating engine (with CHP packages) manufacturers; and one Stirling–cycle engine manufacturer. It is unclear if all of the identified manufacturers will actually sell their products in California, but all have indicated an interest in doing so in the future.

Most of the microturbines located in California are at research facilities and local utility districts and are used primarily to demonstrate their applicability and reliability. To date, only a few units have been purchased and installed for use at commercial sites. The South Coast Air Quality Management District will be placing approximately 150 microturbines at public buildings throughout the district using funds from with the Los Angeles Department of Water and Power (LADWP) and AES Settlement Funds.

The few stationary fuel cells that are operating in California are either located at the United States Department of Defense facilities or are undergoing evaluation by utility companies. The stationary fuel cell community is currently served by one commercial product, a 200 kW phosphoric acid fuel cell. However, the fuel cell manufacturing community is engaged in a strong commercialization effort and is currently establishing a manufacturing capability to meet an emerging market.

Small well-controlled natural gas-fired reciprocating engines (without CHP), using nonselective catalytic reduction, are now available for sale in California. Well-controlled reciprocating engines that are integrated with CHP have been installed at a number of locations in California. One manufacturer of these units indicated to the ARB staff that approximately 100 of their units have been installed in California.

Stirling-cycle engines are expected to be commercialized in 2002.

As can be seen from the information presented above, very few smaller DG technologies are currently being operated in California. However, manufacturers are aggressively pursuing new customers for their technologies and expect to initiate or increase sales in California over the next few years.

IV. EMISSIONS FROM ELECTRICAL GENERATION TECHNOLOGIES

To develop the emission standards required in SB 1298, the ARB staff evaluated emissions data from DG technologies that would be exempt from district permit and BACT determinations for central station power plants. This chapter includes a discussion of the ARB staff's analysis of air emissions from these electrical generation sources.

A. Emissions from DG Technologies

SB 1298 mandates two levels of emission standards for affected DG technologies. The law requires that the first set of standards be effective no later than January 1, 2003, and reflect the best performance achieved in practice by existing DG technologies that are exempt from district permits. The law also requires that, by the earliest practicable date, the standards be made equivalent to the level determined by the ARB to be BACT for permitted central station power plants in California. The emission standards must be expressed in lb/MW-hr to reflect the efficiencies of various electrical generation technologies.

1. Fossil-Fueled Technologies

As was mentioned in the previous chapter, DG sources include fossil-fueled technologies that emit air pollutants and non-polluting zero emission technologies. To evaluate possible emission standards for 2003, the ARB staff had to first analyze source test data for fossil-fueled DG technologies not subject to district permits.

Source test data for these types of technologies are not readily available because these technologies are not required to be source tested for permitting purposes. Although source testing had been conducted on some microturbines at a research center at University of California at Irvine and through the Electric Power Research Institute, this data was not publicly available. Consequently, early in the regulatory development process, the ARB staff requested any available source test data from potentially affected manufacturers to help staff identify the lowest achievable emission levels from these technologies.

The ARB staff received emissions data from manufacturers of three microturbines, one reciprocating engine, and a phosphoric acid fuel cell integrated with a reformer. A summary of the manufacturers' source test data is included in Table 2. The ARB staff also conducted a source test on one microturbine located at an electric utility district office in Sacramento. The test results were comparable to the manufacturers' test data. The ARB source test results can be found in Appendix D.

Table 2-Test Data from Manufacturers

		ppm @ 15% O2				lb/MW-Hr		
	Power level*	NOx	VOC***	CO		NOx	VOC***	CO
Microturbines								
Technology #1	100%	3	0	10		0.2	0	0.4
	75%	1	45	158		0.07	1	6.1
	50%	63	0	46		4.2	0	1.9
Technology #2	100%	5	0	5		0.3	0	7.6
	75%	5	0	125		0.3	0	4.3
	50%	6	14	122		0.4	0.3	4.6
Technology #3	100%	24	3	3		1.2	0.04	0.08
	75%	30	6	5		1.5	0.09	0.2
	50%	63	35	130		3.3	0.5	4.3
Technology #4**	100%	31	na	36		1.3	na	0.9
	75%	28	na	112		1.3	na	3.3
	50%	27	na	220		1.8	na	5.9
Natural Gas Engine Equipped With NonSelective Catalytic Reduction								
Technology #1	SCAQMD BACT level	9	25	55		0.5	0.5	1.9
	Technology Data	3	8	24		0.2	0.2	0.8
Fuel Cells								
Technology #1	100%	2.4	0.7	<0.1		0.06	0.02	<0.002
	50%	2.9	0.9	3.3		0.1	0.04	0.08

All emissions based on using natural gas

* As percent of maximum load

** lb/MW-hr estimated from data submitted in ppm format

*** Data reported as both total hydrocarbons (THC) and VOCs

As was expected, the lowest emissions level in Table 2 came from the fuel cell with the integrated reformer. These emissions are near the level of a central station power plant. On an equivalent energy production basis (i.e. pounds of air pollutant per megawatt-hour of electricity produced), the other DG technologies' emissions were near an order of magnitude (10 times) greater than current BACT limits for central station power plants.

When evaluating emissions limits for DG technologies, the ARB staff also evaluated BACT determinations for DG technologies that were subject to district permit requirements. As indicated in Table 2 above, the South Coast Air Quality Management District's BACT determination for NOx for small natural gas-fired reciprocating engines is equivalent to 0.5 lb/MW-hr, which is comparable to some of the emission levels identified in the manufacturers' source test data.

2. Zero Emission Technologies

Although the proposed emission standards will not apply to nonpolluting technologies, the ARB staff evaluated zero emission technologies and considered standards that would promote hybrid DG technologies that integrate fossil-fueled technologies with zero emission technologies. Zero emission technologies include, but are not limited to, photovoltaic cells, wind turbines, fuel cells that use non-reformer hydrogen sources, and external combustion engines (Stirling-cycle engines) that use only waste heat or solar energy.

B. Central Station Power Plant Emissions

1. BACT Determinations

In order to develop the second required set of emission standards, the ARB staff analyzed BACT determinations for central station power plants in California. The ARB staff used data included in the 1999 ARB report entitled Guidance for Power Plant Siting and Best Available Control Technology (1999 ARB Power Plant Guidance). The report includes BACT determinations for central station power plants that generate 50 megawatts or greater of electricity. Staff reviewed the BACT determination in this report for combined-cycle gas turbines, which is the configuration used in all new central station power plants. As was done for the analysis of data obtained from existing DG technologies, the BACT determinations were converted to an equivalent lb/MW-hr standard assuming an efficiency rate of 50 percent for central station power plants.

2. Line Losses

Some electricity is lost as it is transmitted from central station power plants to the place of use. According to the California Energy Commission, the total system (including transmission and distribution systems) average line loss factor in California is ten percent. Line loss is minimized with DG technologies. Line losses affect the amount of electricity that is ultimately received by the end user and affects the lb/MW-hr emissions rate for central station power plants. Consequently, the ARB staff applied the ten percent total system line loss factor to the BACT determinations to determine the emission rates for central station power plants that DG technologies must ultimately meet. The emission rates are included in Table 3.

Table 3- BACT Determinations for Combined-Cycle Gas Turbine Configurations Greater than 50 MW

	ppm @ 15% O_2				lb/MW-Hr		
Power level*	NOx	VOC	CO		NOx	VOC	CO
100%	2.5	2	6		0.07	0.02	0.10

C. Combined Heat and Power

Combined heat and power applications produce both electric power and process heat from the combustion/processing of the same fuel. Process heat refers to the thermal energy used to heat water that is consumed by the occupants of a building. CHP packages can increase the efficiency of DG technology to over 80 percent. Because of its environmental benefits, the ARB staff considered a credit for CHP applications when proposing emission standards for DG technologies. A CHP credit was developed for both the 2003 and 2007 emission standards.

The 2003 standards include a category for technologies that use 60 percent efficient CHP. The CHP standards are based on crediting the emissions from a boiler that would otherwise have been used to heat water. The ARB staff assumed a boiler emission rate of 30 ppm of NOx, which equates to the reasonable available control technologies (RACT) levels for existing natural gas boilers in most air districts.

A different approach was taken for determining the 2007 CHP credits. The 2007 requirements allow for an energy credit for technologies that use highly efficient CHP. DG technologies that can achieve a minimum efficiency of 60 percent (electrical plus process heat output/fuel used) at all times and an annual average efficiency of 75 percent, can use the credit to meet the 2007 standards. The credit can be determined by allowing the process heat to be added to the total energy production of the DG unit (lb/MW-hr = emissions from unit (lb/hr) / [MW (electrical) + MW (process heat)]) at the rate of 1 MW-hr for each 3.4 million Btu of process heat. This allowance is comparable to the CHP credit in the new Texas rule for electric generating units and is also supported by environmental groups. An example follows:

A unit with a fuel input of 270 kw provides 75 kw of electrical output and an equivalent process heat requirement of 130 kw. The process heat requirement can dip to 90 kw. Emissions are at 3 ppm at 15 percent O_2 or 0.15 lb/MW-hr.

Minimum overall efficiency:	61 percent
Average overall efficiency:	76 percent
lb/MW-hr:	0.15
lb/MW-hr with CHP credit:	0.05

V. THE PROPOSED DG CERTIFICATION PROGRAM

This chapter contains a summary of the proposed DG certification program including proposed emission standards and certification requirements. It also reviews the basis and rationale for selecting the provisions being proposed and the alternatives considered by the ARB staff in developing this proposal. A copy of the proposed certification program requirements is located in Appendix B.

A. Summary of the Proposed Emission Standards and Certification Requirements

1. Affected Sources

After January 1, 2003, manufacturers of new electrical generation units that are exempt from district permit requirements must have their equipment certified by the ARB to the proposed emission standards. There are 35 air districts in California. The ARB staff will assist the manufacturers with determining exemption levels for each district. If a proposed unit is not subject to the district's permit requirements, it must be certified by the ARB before it can be sold, leased, or operated in that district. Equipment operating before January 1, 2003 will not be subject to the proposed standards.

The types of technologies that will be subject to the emission standards are microturbines, reformer-based fuel cells, small reciprocating engines, external combustion engines, or any combination thereof.

Certain types of technologies are exempt from certification. A technology does not have to be certified if it does not emit an air contaminant. This would include zero emission technologies including, but not limited to, wind turbines, photovoltaics, and fuel cells that do not use reformers. A technology does not have to be certified if it is registered under the ARB's Portable Equipment Registration Program (PERP). Equipment used in portable applications is already subject to emission standards under PERP. A technology does not have to be certified if it is to be used only when electrical or natural gas service fails or for emergency pumping of water for fire protection or flood relief.

2. Emission Standards

DG technologies must be certified to two levels of emission standards by two different deadlines with the ultimate standards reflecting current BACT determinations for central station power plants, as required by SB 1298. The first set of standards is effective on January 1, 2003, as required by SB 1298. The second, more stringent, set of standards will become effective on January 1, 2007.

a. 2003 Emission Standards

The 2003 standards have been set for NOx, CO, VOCs (as defined in ARB Test Method 100), and PM. The standards are based on the ARB staff's review of manufacturers' source test data (with the exception of the PM standard, which is based on fuel sulfur content). The California Public Utility Commission regulates sulfur content in natural gas. The two major California utility companies that purchase natural gas specify levels no higher that one grain of total sulfur per 100 standard cubic feet (1 gr/100 scf). As was done in the 1999 ARB Power Plant Guidance, an emission limit for PM will correspond to natural gas with fuel sulfur content of not more than 1 grain/100 scf, as supplied by a regulated entity. The manufacturers' source test data were all based on natural gas fuel.

Emission standards have been set for 2003 for DG units that are not integrated with combined heat and power packages, and for DG units that are integrated with combined heat and power packages. Table 4 presents the proposed 2003 emission standards.

Table 4- 2003 Emission Standards

Pollutant	DG Unit not Integrated With Combined Heat and Power	DG Unit Integrated With Combined Heat and Power
Oxides of Nitrogen (NO_x)	0.5	0.7
Carbon Monoxide (CO)	6.0	6.0
Volatile Organic Compounds (VOCs)	1.0	1.0
Particulate Matter (PM)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf

DG units that are certified without integrated CHP must meet the more stringent standard. These standards are based on achievable limits that were determined from the ARB staff's review of DG manufacturers' emissions data. DG units that are certified with integrated CHP are given an emission credit that is reflected in a slightly higher emission standard value. The emission credit is equivalent to the emissions from a boiler that would otherwise be used to produce the process heat coming from the DG unit. These standards provide recognition of the emissions benefits of CHP applications. The CHP standards can be used by the manufacturer if the DG technology is integrated with the CHP package and the unit can achieve a minimum 60 percent efficiency (electrical and process heat output/fuel used).

A manufacturer can use an energy credit for meeting either set of emission standards if the DG unit is integrated and certified with a zero emission technology including, but not limited to, a photovoltaic cell, wind turbine, non-reformer fuel cell, or Stirling-cycle engine that uses waste heat or solar energy. The electrical output of the zero emission technology can be added to the electrical output of the DG unit subject to certification to calculate the lb/MW-hr emission rate of the integrated package.

b. 2007 Emission Standards

The 2007 emission standards are based on the 1999 Board approved BACT determinations for central station power plants with an adjustment for a ten percent total system average line loss factor. Highly efficient DG technologies that are integrated with CHP packages will be able to use an energy credit to meet the emission levels.

Manufacturers have indicated to the ARB staff that it takes a minimum of four years to research and develop a new product. The 2007 compliance date was chosen to provide manufacturers a five year lead time (from the time the certification program is approved by the Board) to develop a technology that can meet the stringent standards for central station power plants. The 2007 emission standards are presented in Table 5.

Table 5 -2007 Emission Standards

Pollutant	Emission Standard (lb/MW-hr)
Oxides of Nitrogen (NO_x)	0.07
Carbon Monoxide (CO)	0.10
Volatile Organic Compounds (VOCs)	0.02
Particulate Matter (PM)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf

Manufacturers of DG technologies that are integrated with CHP will be able to calculate an energy credit for the usable process heat. This credit can be used to meet the 2007 standards. The credit allows the process heat to be added to the total energy production of the DG unit at the rate of 1 MW-hr for each 3.4 million Btu of process heat produced. To encourage the use of high efficiency CHP, the credit can be taken when the DG technology is integrated with the CHP package, and the unit can achieve a minimum 60 percent efficiency (electrical and process heat output/fuel used) at all times and an annual average efficiency of 75 percent.

c. Demonstration of Emissions Durability

Manufacturers must demonstrate that the 2003 and 2007 emission standards can be met for 15,000 hours of operation when the DG units are operated and maintained according to manufacturers' recommendations. The 15,000 hours requirement is within the expected useful life of nonselective catalytic reduction units that may be integrated with some technologies (e.g. reciprocating engines) seeking certification and are also within many manufacturers' warranty periods. Applicants will be asked to provide a plan to the ARB that outlines how they will demonstrate that their product meets or will meet the standards for 15,000 hours. Some technologies are so new that they have not yet run for 15,000 hours. In these cases, manufactures can perform a statistical analysis that predicts changes in emission rates from the equipment over time. This practice is consistent with other certification programs conducted by the ARB.

d. Electrical Generation Technology Review

DG technologies are just beginning to enter the market. The future operating conditions and operational modes for these technologies and ability to maintain emission standards are uncertain at this time. Source testing methods and protocols may need further refinement and customizing to account for the range of DG applications. To address these concerns, the ARB staff will complete another review of DG technologies and emissions data and report the findings to the Board by July 2005. This will provide manufacturers and the ARB staff two and a half years after the first set of standards are in place to collect information on the performance and capabilities of their technologies.

The review will also include evaluations of any new BACT determinations for central station power plants and any control measures under development or recently adopted by the ARB that could have a bearing on the 2007 standard.

3. Application Process

Manufacturers seeking certification will submit an application package to the ARB for review. Application forms will be available on ARB's DG website at *http://www.arb.ca.gov/energy/dg/dg.htm*

The following information must be submitted to determine if the DG unit is eligible for certification:

- Name of the applicant and contact information;

- a description of the DG unit and model number;
- maximum output rating (kilowatt);
- fuel for which certification is being sought;
- any air pollution control equipment that is integrated with the technology; and
- emissions test data, supporting calculations, quality control/assurance information, and all other information needed to demonstrate compliance with the emission standards and durability requirements.

Upon finding that the DG technology meets the requirements for certification, an Executive Order of Certification will be issued by the ARB. The Executive Order will describe the DG unit and indicate if the unit was certified with an integrated CHP package, zero emission technology, and/or air pollution control equipment. The Executive Order will also indicate that the certification is required only in those districts where the specific DG unit is exempt from district permit requirements.

4. Testing Requirements

Manufacturers must include a source test report with their certification application demonstrating the emission limits of their equipment. ARB test methods or alternative approved test procedures must be used. The test cycle will be similar to the D1 test cycle in the International Organization for Standardization (ISO) 8178 standard. Each valid test run must be conducted for three power production loads: 50, 75, and 100 percent of generator gross output. For each valid test run, the results for each tested load shall be averaged according to the following weighting factors:

1) 50 percent load results shall be given 20 percent weight;
2) 75 percent load results shall be given 50 percent weight; and
3) 100 percent load results shall be given 30 percent weight.

Three valid runs must be conducted on the equipment. (This is standard source testing procedure.) In order to express the emission rates in lb/MW-hr, the electricity generated must be measured during each run. Before commercial operation, each DG unit manufactured for sale, lease, or use in California must be monitored for NOx emissions at full power using an approved NOx screening device. Manufacturers of DG technologies that can meet the 2007 standards by 2003 (such as fuel cells with reformers) will not be required to monitor for NOx emissions. This monitoring information may be requested by the ARB staff at a later date as part of a quality control review of the equipment's test data.

5. Other Requirements and Provisions

Provisions are included to allow zero emission technologies to seek voluntary certification. Some manufacturers of these technologies may want

ARB certification for marketing purposes. Label requirements are included and are designed to be consistent with other engine certification programs and to provide flexibility to manufacturers to meet the labeling needs of various certification entities. The labels must contain the year of the conforming emission standards, the fuel type used for certification and the number of the Executive Order of Certification. Certifications are valid for four years or until January 1, 2007. Some manufacturers may be certified between the years 2003 and 2007 and can only meet the 2003 emission levels. These manufacturers' applications would only be valid until January 1, 2007.

6. Certification Fees

To recover the cost incurred by the ARB staff to process a request for DG certification, a $2,500 application fee will be due at the time an application package is submitted. Technologies seeking a recertification (every four years) will be assessed a $2,500 fee. To provide an economic incentive for the cleanest DG technologies, DG units that can meet the 2007 standard by 2003 will not be assessed a fee for 2003 certifications. For the same reason, zero emission technologies that are seeking voluntary certification will not be assessed a fee.

7. Enforcement

Provisions have been included for revoking, denying, or suspending a certification for specific reasons. Provisions for inspections of certified units are also included. Manufactures may be subject to penalties if found to be in violation of the certification requirements.

B. Basis and Rationale for Certification Requirements

SB 1298 requires the ARB to set emission standards for DG technologies not subject to district permit requirements and to develop a certification program for these technologies. The ARB staff used a number of methods to develop what we believe are reasonable emission standards and certification requirements. The ARB staff contacted staff from other certification programs such as the South Coast Air Quality Management District's Water Heater Certification Program (Rule 1121) and the ARB's Small Off-Road Engines (SORE) program to gain a general understanding of establishing a certification program. The ARB staff also evaluated emission standards and requirements in the Texas Natural Resource Conservation Commission's new rule for electric generating units.

The ARB staff gathered source test data from manufacturers and reviewed air district rules to determine achievable emission limits for these technologies. The ARB staff also communicated with manufacturers and toured sites housing DG units to gain an understanding of their design and the process that would be involved with redesigning them to meet tighter standards.

The ARB staff believes the proposal addresses the requirements in the statute, public health protection, the impacts on industry, and presents the most reasonable approach to meeting the mandates of SB 1298.

C. Alternatives Considered

1. No Action

One alternative would have been not to develop the proposed DG certification program and emission standards. This alternative, however, would not satisfy the mandates in SB 1298.

2. Set 2003 Emission Standards at Zero or Near-Zero Limits

Another alternative would have been to set the 2003 emission standards at zero or near zero, which can be achieved by some types of DG technologies such as wind turbines, fuel cells, and photovoltaic cells. However, this alternative would eliminate most fossil-fueled DG technologies from the certification process and from competition in California.

3. Set Final Emission Standards at a Later Date

A third alternative would have been to extend the compliance date for the emissions standards that reflect BACT levels for central station power plants (2007 standards). This alternative would delay the intent of the legislation, which is to protect public health from exposure to electrical generation sources at the earliest practicable date.

Manufacturers have indicated that it takes about four years to develop a new product. Manufacturers will have to redesign their DG technologies and increase their efficiencies to meet 2007 standards. Consequently, the ARB staff has proposed a four-year interval between the required 2003 emission standards and the final emission standards that must reflect BACT for central station power plants. To assist manufacturers with meeting these standards, the ARB staff included provisions for an energy credit for technologies that are integrated with highly efficient CHP packages.

The ARB staff is aware that it will be difficult for some DG technologies to ever meet emission levels from central station power plants, regardless of the compliance date. For example, manufacturers of small natural gas reciprocating engines will need to greatly increase their electrical efficiency and add additional air pollution control equipment to meet the 2007 standard, which may be cost prohibitive. However, a number of engine manufacturers and the U.S. Department of Energy (DOE) are working together on the Advanced Reciprocating Engine Systems (ARES) program. The goal of this program is to create a natural gas powered engine that will be at least 50 percent efficient. Although this program is applicable to engines greater than 1 MW, the information gained from the program could be applied to smaller engines to assist them with ultimately meeting the 2007 standards.

D. Alternatives that Would Lessen Impacts on Small Business

The ARB staff has determined that about 50 percent of potentially affected manufacturers are small businesses. All but one of these businesses are manufacturers of fuel cells. It will be several years before most of these manufacturers are at the commercialization stage and some of these businesses may, for various reasons, never sell products in California. Consequently, the potential impacts of complying with the proposed requirements on these small businesses are uncertain at this time. Provisions have been included in the proposed program to exempt the fee for fuel cell certification applications submitted to the ARB staff before January 1, 2007. Provisions have also been included to provide credits that other small manufacturers can use to help them comply with the certification requirements.

VI. POTENTIAL HEALTH IMPACTS OF PROPOSED CERTIFICATION PROGRAM

This chapter discusses the potential health impacts of the proposed certification program, including the benefits of the proposed emission standards and their potential health impacts.

No adverse health impacts are expected from the proposed certification program. The emission standards in the certification requirements are more beneficial to public heath than the much higher emissions that are currently allowed to be emitted from these unpermitted sources. If uncontrolled, emissions from DG technologies could negatively impact air quality and public health. On an equivalent energy production basis (i.e. pounds of air pollutant per kilowatt - hour of electricity produced), DG emissions can be an order of magnitude higher than emissions from central station power plants. Consequently, if more power production shifts from central station power plants to near-the-place-of-use electrical generation, air emissions and associated exposure to California citizens could increase. Setting state-of-the-art emission standards now for emerging DG technologies will help protect California citizens from these new sources of air emissions. In addition, encouraging these DG technologies to meet central station power plant emission levels as soon as practicable will further protect public health in California.

The proposed DG certification program promotes the use of combined heat and power which increases the efficiency of the fuel used in the certified DG technology. Increasing the efficiency of these units results in lower fuel consumption and reduces overall air emissions including carbon dioxide, a greenhouse gas. This, in turn, reduces the impact on global warming. The ARB staff's proposal also promotes the use of zero emission technologies such as wind turbines, photovoltaics and non-reformer fuel cells. These technologies have no air emissions, and thus have a positive impact on public health.

Through the proposed DG certification program, the ARB will be regulating new DG sources before they enter the market. Future emission inventories for California will reflect the lowest practical emissions levels from these sources.

The ARB staff could have set 2003 standards at zero or near zero levels, which can be achieved by some types of DG technologies such as wind turbines, fuel cells, and photovoltaic cells. More stringent 2003 emission standards would be more protective of public health. However, this alternative would eliminate most fossil-fueled DG technologies from the certification process and from competition in California. It would also drastically reduce the types and numbers of DG technologies that are available to California users and could increase product cost.

The ARB staff could have required central station power plant emission levels to be met before 2007. Requiring DG technologies to meet these emission levels before 2007 would also be more protective of public health. However, similar to the argument above, this alternative would eliminate most fossil-fueled DG technologies from the certification process and from competition in California. Based on our conversations with manufacturers, it takes four years to research and develop a new product. The 2007 compliance date was chosen to provide manufacturers a five year lead time (from the time the certification program is approved by the Board) to develop a technology that can meet the stringent standards for central station power plants and stay competitive in California.

VII. ENVIRONMENTAL IMPACTS OF PROPOSED CERTIFICATION PROGRAM

The ARB staff has conducted an analysis of the potential environmental impacts of the proposed DG certification program. Based on our analysis, we have determined that the proposed DG program would have no significant adverse environmental impacts.

A. Legal Requirement

The California Environmental Quality Act (CEQA) and the ARB policy require an analysis to determine the potential adverse environmental impacts of proposed regulations. Since the ARB's program involving the adoption of regulations has been certified by the Secretary of Resources (see Public Resources Code section 21080.5), the CEQA environmental analysis requirements are allowed to be included in the Initial Statement of Reasons for a rulemaking in lieu of preparing an environmental impact report or negative declaration. In addition, the ARB will respond in writing to all significant environmental issues raised by the public during the public review period at the Board hearing. These responses will be contained in the Final Statement of Reasons for the proposed DG certification program.

Public Resources Code section 21159 requires that the environmental impact analysis conducted by the ARB include the following: (1) an analysis of the reasonably foreseeable environmental impacts of the methods of compliance; (2) an analysis of reasonably foreseeable feasible mitigation measures; and, (3) an analysis of reasonably foreseeable alternative means of compliance with the proposed DG certification program. Regarding reasonably foreseeable mitigation measures, CEQA requires an agency to identify and adopt feasible mitigation measures that would minimize any significant adverse environmental impacts described in the environmental analysis.

B. Reasonably Foreseeable Environmental Impacts of the Methods of Compliance with the DG Certification

The ARB staff has not identified any significant adverse environmental impacts from complying with the emission standards in the certification program. A few possible environmental impacts are:

1) A reciprocating engine manufacturer seeking certification by ARB staff may have to add a catalyst to the DG unit in order to meet the proposed emission standards. Used catalyst material may be considered hazardous waste, but there are methods for properly disposing of this type of waste. The used material can be

processed in such a way that it is no longer considered hazardous waste, and the waste can then be disposed of as solid waste.

2) The proposed emission standards essentially limit DG units to natural gas. This could reduce the supply of natural gas for other sectors of the market. However, DG units account for a very small portion of the total natural gas market.

C. Reasonably Foreseeable Feasible Mitigation Measures

As previously discussed, ARB is required to do an analysis of reasonably foreseeable feasible mitigation measures. ARB staff has concluded that no significant adverse environmental impacts should occur from implementation of the proposed certification program. As a result, no mitigation measures would be necessary.

D. Reasonably Foreseeable Alternative Means of Compliance with the DG Certification Program

The ARB is required to do an analysis of reasonably foreseeable alternative means of compliance with the proposed certification program. Alternatives to the proposed certification program are discussed in Chapter V. Based on the discussions in Chapter V, the ARB staff concluded that the proposed DG certification program provides the greatest degree of flexibility and the least burdensome approach to reducing public exposure to emissions from new DG technologies.

E. Environmental Justice

The ARB is committed to evaluating community impacts of proposed regulations, including environmental justice concerns. The proposed DG certification program is not expected to result in significant negative impacts in any community. The result of the certification program will be reduced exposures to new small sources of electrical generation for all communities.

F. State Implementation Plan Impacts

DG technologies have not yet penetrated the California market and are not part of the inventory that is used for the State Implementation Plan. Through the proposed DG certification program, the ARB will be regulating these new sources before they enter the market. As was mentioned earlier, future emission inventories will reflect the lowest emissions achievable from these sources.

VIII. ECONOMIC IMPACTS OF PROPOSED CERTIFICATION PROGRAM

This chapter discusses the economic impacts that the proposed DG certification program may have on businesses.

Manufacturers' efforts to comply with the 2003 emission standards are not expected to result in any significant adverse economic impacts. All but one potentially affected manufacturer have indicated to the ARB staff that they expect their technologies to meet the 2003 emission standards by January 1, 2003. One manufacturer indicated that it is incurring a one to two million-dollar research and development cost to redesign its technology to meet the 2003 standards. However, the certification requirements was one of several factors that determined the manufacturer's decision to redesign its product, included interest in developing an environmentally friendly product, and meeting emissions requirements in other states' air regulations.

Efforts to comply with the 2007 emission standards could result in an adverse economic impact on a few manufacturers. A few manufacturers have indicated that they will incur research and development costs to redesign their technologies to meet the 2007 standards which could also result in a higher product cost. A few manufacturers indicated to the ARB staff that it may cost several million dollars to accomplish their redesign. The ARB staff is also aware that it will be difficult for some DG technologies such as reciprocating engines to ever meet BACT levels for central station power plants, regardless of compliance dates, because of the prohibitive cost of additional emission control devices that would be needed to meet the standards. However, manufacturers can use an energy credit if they sell their products integrated with CHP packages. With this credit, fewer add-on controls and/or product redesign would be needed to allow the DG unit to meet the 2007 standard.

Some technologies may not initially or may never meet the emission standards, which may delay availability or reduce product choices. This could potentially increase the price of DG technologies. Also products may increase in price when manufacturers redesign their products to meet the 2007 standards. To offset these possibilities, the ARB staff's proposal provides credits for CHP and zero emission technology packages to enable manufacturers to remain competitive and still meet the emission standards established by SB 1298.

The overall statewide cost of the proposed certification program for the 2003 standards is estimated to be $370,000 with an estimated individual business cost of $11,000 to $21,500. Businesses will incur costs for conducting an emissions source test on the DG model that is being certified, preparing a certification application, which includes supporting documentation, and paying an application fee.

Because most DG technologies are just entering the commercialization stage, the ARB staff is unable to determine the cost for manufacturers to comply with the proposed 2007 levels at this time. Compliance costs for the 2007 standard will be evaluated in more detail during the ARB staff's technical review in 2005, when more information becomes available on DG technologies.

The proposed certification program is not expected to cause a noticeable change in California employment or business status. The proposed regulation may have a positive impact on business by providing incentives for zero emission technologies (e.g. non-reformer fuel cells, wind turbines and photovoltaics) to penetrate the California market and expand production.

A. Legal Requirement

Section 11346.3 of the Government Code requires State agencies to assess the potential for adverse economic impacts on California business enterprises and individuals when proposing to adopt or amend any administrative regulation. The assessment shall include a consideration of the impact of the proposed regulation on California jobs, business expansion, elimination, or creation, and the ability of California businesses to compete.

Also, State agencies are required to estimate the cost or savings to any State or local agency and school district in accordance with instructions adopted by the Department of Finance. The estimate shall include any non-discretionary cost or savings to local agencies and the cost or savings in federal funding to the State.

Health and Safety Code section 57005 requires the ARB staff to perform an economic impact analysis of submitted alternatives to a proposed regulation before adopting any major regulation. A major regulation is defined as a regulation that will have a potential cost to California business enterprises in an amount exceeding ten million dollars in any single year. The proposed certification program is not a major regulation.

B. Businesses Affected

The businesses that may be affected by the DG certification program fall primarily into four Standard Industrial Classifications (SICs)/new North American Industry Classifications (NAICs). A list of the industries that the ARB staff has been able to identify is provided in Table 6.

Table 6- Potential Industries Affected by the Proposed Distributed Generation Certification Program

SIC/NAIC	Industry
3511/333611	Turbine and turbine generator set units manufacturing
3519/333618	Other engine equipment manufacturing
3621/335312	Motor and generator manufacturing
3629/335999	Fuel cells, electrochemical generators manufacturing

The ARB staff has identified 25 manufacturers that will potentially be impacted by the proposed certification program. Only four of these companies are in California. The manufacturers include the following: 4 microturbine manufacturers; 4 reciprocating engine manufacturers (with and without combined heat and power packages); 1 external combustion (Stirling-cycle) engine manufacturer; and up to 16 fuel cell manufacturers. It is unclear if all of the identified manufacturers will actually sell their products in California, but all have indicated an interest in doing so in the future. Table 7 summarizes potentially affected manufactures by technology type and location.

Table 7- DG Manufactures by Technology Type and Location

DG Technology	Non-California Company	California Company	Total
Microturbines	3	1	4
External Combustion Engines	1	0	1
Internal Combustion Engines	3	1	4
Fuel Cells	14	2	16
Total	21	4	25

C. Cost Impacts to Businesses

Costs to affected businesses for complying with the proposed certification requirements can be divided into three major areas: the cost of an application fee, the cost for preparing a certification application package, and the cost to perform emission source testing. The three major areas are listed below:

1. Application Fees

Initial certification under the proposed certification program will require an application fee of $2,500. This fee is based on an estimate of 40 hours of the ARB staff time to review the certification applications. Manufacturers of technologies that are seeking voluntary certification (those technologies that do not emit an air contaminant) will not be required to submit a fee. Manufacturers of technologies that meet the 2007 emission standards by 2003 will not be required to submit a fee for 2003 certification. Certifications are valid for four years. A $2,500 fee is proposed for recertification.

2. Application Preparation Costs

Based on the ARB staff's communications with manufacturers, the estimated cost to prepare a certification application package that contains all of the required information and supporting data is $6,000. This estimate is based on the hourly labor cost of $75 per hour for 80 hours.

3. Source Testing Costs

Manufacturers will be required to provide a source test report in their certification application to demonstrate compliance with the proposed emission standards. The estimated cost for performing the source tests and analyzing the results is $5,000. The cost estimate is based on surveying private source testing companies.

Manufacturers, except manufacturers of DG technologies that can meet the 2007 standards by 2003 (such as fuel cells with reformers), will be required to monitor the NOx emissions of each new DG unit that is manufactured for sale, lease or operation in California prior to its commercial operation. The monitoring can be performed using a portable NOx analyzer that is calibrated according to U.S. EPA's Conditional Test Method 22. Some manufacturers may have to purchase a portable analyzer to comply with this requirement. One manufacturer gave the ARB staff an estimate of $8,000 for purchasing an acceptable NOx analyzer.

The overall statewide cost for complying with the 2003 standards is estimated to be $370,000 with an estimated individual business cost of $11,000 to $21,500. Table 8 presents the cost per technology type to comply with the 2003 standards.

Table 8-Cost for Complying with DG Certification Requirements per Technology

DG Technology	Number of Manufacturers	Cost ($)	Total ($)
Microturbines	4	21,500	86,000
External Combustion Engines	1	21,500	21,500
Internal Combustion Engines	4	21,500	86,000
Fuel Cells*	16	11,000	176,000
Total Cost			369,500

* Assuming all potentially affected fuel cell manufacturers will be using a reformer.

Manufacturers have indicated that they will have to redesign or increase add-on emission control devices to their technologies to meet the 2007 standards. To minimizing the economic impact to manufacturers for complying with these standards, the ARB staff included provisions in the certification requirements for an energy credit for highly efficient combined heat and power packages that are integrated with DG technologies. Manufacturers may choose to sell their units in 2007 with integrated CHP to possibly reduce their redesign or add-on emission control costs.

Because most DG technologies are currently at the development stage, the ARB staff is unable to determine the cost for manufacturers to comply with the proposed 2007 standards at this time. A few manufacturers have indicated that it could take several million dollars of research and development cost to comply with the 2007 standard. Compliance cost for the 2007 standard will be evaluated in more detail during the ARB staff's technical review in 2005, when more information becomes available on DG technologies.

D. Potential Impact on Business Competitiveness

The proposed regulation is not expected to adversely impact California business competitiveness because all affected manufacturers that make products for sale into California will be required to meet the same emission standards requirements. Of the 25 potentially affected DG manufacturers that the ARB staff was able to identify, only four are located in California.

E. Potential Impact on Employment

The proposed regulation is not expected to cause a noticeable change in California employment. The proposed regulation may actually have a positive impact on employment by providing incentives for zero emission technologies (e.g. non-reformer fuel cells, external combustion engines using waste heat or solar energy, wind turbines, and photovoltaics) to penetrate the California market and expand production.

F. Potential Impact on Business Creation, Elimination, or Expansion

No significant change is expected to occur to the California business status as a result of the proposed DG program.

G. Potential Impact on State or Local Agencies

The proposed certification program should have no significant economic impact on state or local agencies. There are no state or local agencies that manufacture DG technologies.

The ARB will incur costs in 2002 to certify distributed generation technologies to the January 1, 2003 emission standards. The proposed certification fee of $2,500 will offset these costs. The ARB staff will also conduct outreach in 2002 to educate stakeholders on the DG certification requirements, and will be conducting a technical review of DG technologies in 2005 to determine if the 2007 emission standards and other proposed requirements should be revised. The ARB staff submitted a Budget Change Proposal (BCP) to add two person years to ARB's budget for implementing the requirements of SB 1298, which will include the outreach and technical review. The BCP was approved by the Department of Finance and became effective for Fiscal Year 2001-2002.

The ARB staff will also be responsible for enforcing the requirements in the DG certification program including ensuring that DG units are meeting their certified limits in the field. Additional resources may be needed for the ARB staff to perform inspection and/or field testing of certified units. Testing equipment may be purchased to perform the field tests. Enforcement may require one additional full time position. It is not known now whether existing personnel will be reassigned to this or new personnel hired. The cost for these additional resources may be $100,000 per year, as well as, a one-time cost of $50,000 for testing equipment.

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Appendix A

California Senate Bill 1298 (Bowen and Peace)

BILL NUMBER: SB 1298
CHAPTERED BILL TEXT

CHAPTER 741	
FILED WITH SECRETARY OF STATE	SEPTEMBER 27, 2000
APPROVED BY GOVERNOR	SEPTEMBER 25, 2000
PASSED THE SENATE	AUGUST 31, 2000
PASSED THE ASSEMBLY	AUGUST 29, 2000
AMENDED IN ASSEMBLY	AUGUST 25, 2000
AMENDED IN ASSEMBLY	AUGUST 18, 2000
AMENDED IN ASSEMBLY	AUGUST 7, 2000
AMENDED IN ASSEMBLY	JUNE 26, 2000
AMENDED IN SENATE	MAY 28, 1999
AMENDED IN SENATE	APRIL 5, 1999

INTRODUCED BY Senators Bowen and Peace

MARCH 1, 1999

An act to add Sections 41514.9 and 41514.10 to the Health and Safety Code, relating to air pollution.

LEGISLATIVE COUNSEL'S DIGEST

SB 1298, Bowen. Air emissions: distributed generation.

(1) Existing law requires the State Air Resources Board to consider and adopt specified findings before adopting rules or regulations that would affect the operation of existing powerplants. Under existing law, except as specified, any person who violates any statute, rule, regulation, permit, or order of the state board or of an air pollution control strict or an air quality management district relating to air quality, as provided, is guilty of a misdemeanor and is subject to a fine, imprisonment, or both.

This bill would require the state board, on or before January 1, 2003, to adopt a certification program and uniform emission standards for electrical generation that are exempt from district permitting requirements, and would require that those standards reflect the best performance achieved in practice by existing electrical generation technologies.

The bill would require the state board, on or before January 3, 2003, to issue guidance to districts on the permitting or certification of electrical generation technologies under their regulatory jurisdiction, as prescribed.

Since a violation of the regulations adopted pursuant to the bill would be a crime, the bill would impose a state-mandated local program.

(2) The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for a specified reason.

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1. The Legislature finds and declares all of the following:

(a) Distributed generation can contribute to helping California meet the energy requirements of its citizens and businesses.

(b) Certain distributed generation technologies can create significant air emissions.

(c) A clear set of rules and regulations regarding the air quality impacts of distributed generation will facilitate the deployment of distributed generation.

(d) The absence of clear rules and regulations creates uncertainty that may hinder the deployment of distributed generation.

(e) It is in the public interest to encourage the deployment of distributed generation technology in a way that has a positive effect on air quality.

(f) It is the intent of the Legislature to create a streamlined and seamless regulatory program, whereby each distributed generation unit is either certified by the State Air Resources Board for use or subject to the permitting authority of a district.

SEC. 2. Section 41514.9 is added to the Health and Safety Code, to read:

41514.9. (a) On or before January 1, 2003, the state board shall adopt a certification program and uniform emission standards for electrical generation technologies that are exempt from district permitting requirements.

(b) The emission standards for electrical generation technologies shall reflect the best performance achieved in practice by existing electrical generation technologies for the electrical generation technologies referenced in subdivision (a) and, by the earliest practicable date, shall be made equivalent to the level determined by the state board to be the best available control technology for permitted central station powerplants in California. The emission standards for state certified electrical generation technology shall be expressed in pounds per megawatt hour to reflect the expected actual emissions per unit of electricity and heat provided to the consumer from each permitted central powerplant as compared to each state certified electrical generation technology.

(c) Commencing on January 1, 2003, all electrical generation technologies shall be certified by the state board or permitted by a district prior to use or operation in the state. This section does not preclude a district from establishing more stringent emission standards for electrical generation technologies than those adopted by the state board.

(d) The state board may establish a schedule of fees for purposes of this section to be assessed on persons seeking certification as a distributed generator. The fees charged, in the aggregate, shall not exceed the reasonable cost to the state board of administering the certification program.

(e) As used in this section, the following definitions shall apply:

(1) "Best available control technology" has the same meaning as defined in Section 40405.

(2) "Distributed generation" means electric generation located near the place of use.

SEC. 3. Section 41514.10 is added to the Health and Safety Code, to read:

41514.10. On or before January 1, 2003, the state board shall issue guidance to districts on the permitting or certification of electrical generation technologies under the districts regulatory jurisdiction. The guidance shall address best available control technology determinations, as defined by Section 40405, for electrical generation technologies and, by the earliest practicable date, shall make those equivalent to the level determined by the state board to be the best available control technology for permitted central station powerplants in California. The guidance shall also address methods for streamlining the permitting and approval of electrical generation units, including the potential for precertification of one or more types of electrical generation technologies.

SEC. 4. No reimbursement is required by this act pursuant to Section 6 of Article XIIIB of the California Constitution because the only costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIIIB of the California Constitution.

Appendix B

Proposed Regulation Order
Establish a Distributed Generation Certification Program

PROPOSED REGULATION ORDER

ESTABLISH A DISTRIBUTED GENERATION CERTIFICATION PROGRAM

Adopt new sections 94200-94214, in article 3, subchapter 8, chapter 1, division 3 of title 17, California Code of Regulations, to read as follows:

Article 3. **Distributed Generation Certification Program**

94200. **Purpose.**

These regulations implement the program mandated by Health and Safety Code section 41514.9 for certification of electrical generation technologies. After January 1, 2003, it will be unlawful to either:

(a) manufacture any Distributed Generation Unit for sale, lease, use, or operation in the State of California, or

(b) sell or lease, or offer for sale or lease any Distributed Generation Unit for use or operation in the State of California,

unless the Distributed Generation Unit is certified by the Air Resources Board pursuant to these regulations or is otherwise exempt from certification as hereinafter provided.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94201. **Applicability**

Any Distributed Generation Unit manufactured after January 1, 2003 for sale, lease, use, or operation in the State of California or any new Distributed Generation Unit sold or leased, or offered for sale or lease, for use or operation in the State of California after January 1, 2003 shall be certified by the Air Resources Board unless the Distributed Generation Unit:

(a) does not emit an air contaminant when operated,

(b) is registered under the Portable Engine and Equipment Registration Program (title 13, California Code of Regulations commencing at section 2450),

(c) is used only when electrical or natural gas service fails or for emergency pumping of water for fire protection or flood relief, or

(d) is not exempt from an air pollution control district or air quality management district's permitting requirements.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94202. **Definitions**

For the purposes of these regulations, the following definitions apply:

(a) **Air Contaminant**. Shall have the same meaning as set forth in section 39013 of the Health and Safety Code.

(b) **Air Pollution Control Equipment**. Equipment that eliminates, reduces, or controls the issuance of air emissions.

(c) **Applicant.** A manufacturer or manufacturer's designated agent applying for certification of a DG Unit.

(d) **ARB**. The California Air Resources Board.

(e) **Combined Heat and Power**. A DG Unit that produces both electric power and process heat.

(f) **Distributed Generation (DG) Unit**. Electrical generation technologies that produce electricity near the place of use.

(g) **District.** Same meaning as set forth in part 3, commencing with section 40000 of the California Health and Safety Code.

(h) **Electrical Generation Technology**. Reciprocating engines, external combustion engines, combustion turbines, photovoltaics, wind turbines, fuel cells or any combination thereof.

(i) **Executive Officer**. The Executive Officer of the California Air Resources Board or his or her designee.

(j) **Executive Order**. An order issued by the Executive Officer of the Air Resources Board certifying compliance of a DG Unit with the applicable requirements of this article.

(k) **Zero Emission Technology**. Any technology that does not emit an air contaminant as defined in section 94202(a).

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94203. **Requirements.**

(a) On or after January 1, 2003, any DG Unit subject to this regulation must be certified pursuant to section 94204 to one of the following sets of emission standards.

(1) DG Unit not integrated with combined heat and power,
(2) DG Unit integrated with combined heat and power technology.

January 1, 2003 Emission Standards (lb/MW-hr)

Pollutant	DG Unit not Integrated with Combined Heat and Power	DG Unit Integrated With Combined Heat and Power
Oxides of Nitrogen (NO_x)	0.5	0.7
Carbon Monoxide (CO)	6.0	6.0
Volatile Organic Compounds (VOCs)	1.0	1.0
Particulate Matter (PM)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf

(A) DG Units that use combined heat and power (CHP) may be certified to the emission standard in section (a)(2) above if the DG Units are sold with CHP technology integrated into a standardized package by the Applicant and the DG Units achieve a minimum efficiency of 60 percent (useful energy out/fuel in).

(B) DG Units that are sold with a zero emission technology integrated into a standardized package by the Applicant may have the electrical power output of the zero emission technology added to the electrical power output of the DG unit to meet the emission standards in (a)(1) and (a)(2) above.

(b) On or after January 1, 2007, any DG Unit subject to this regulation must be certified pursuant to section 94204 to the following set of emission standards.

January 1, 2007 Emission Standards (lb/MW-hr)

Pollutant	Emission Standard
Oxides of Nitrogen (NO_x)	**0.07**
Carbon Monoxide (CO)	**0.10**
Volatile Organic Compounds (VOCs)	**0.02**
Particulate Matter (PM)	**An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf**

(1) DG Units that use combined heat and power (CHP) may take a credit to meet the emission standard above. Credit shall be at the rate of one megawatt-hour (MW-hr) for each 3.4 million British Thermal Units (BTU's) of heat recovered. To take the credit, the following must apply:

(A) DG Units are sold with CHP technology integrated into a standardized package by the Applicant; and

(B) DG Units achieve a minimum efficiency of 60 percent (useful energy out/fuel in) in the conversion of the energy in the fossil fuel to electricity and process heat, and a minimum average efficiency of 75 percent in the conversion of the energy in the fossil fuel to electricity and process heat.

(c) DG Units must meet the applicable emission standards for 15,000 hours of operation when operated and maintained according to the manufacturer's instructions.

(d) By July 2005, the ARB staff must complete an electrical generation technology review to evaluate if the requirements in (b) and (c) above and section 94207 should be modified and report its findings to the Board.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94204. **Certification Procedure.**

(a) Each application for certification and the fee as specified in section 94210 shall be submitted in a format approved by the Executive Officer and include, at a minimum, the following information:

(1) name of the Applicant, a contact person, mailing address (street and electronic), and telephone number;

(2) a description of the DG Unit and model number;

(3) maximum output rating (kilowatt);

(4) fuel for which certification is being sought;

(5) any emission control equipment;

(6) emissions test data, supporting calculations, quality control/assurance information, and all other information needed to demonstrate compliance with the requirements in sections 94203 (a) through (c).

(b) Within 30 calendar days of receipt of an application, the Executive Officer shall inform the Applicant in writing if the application is complete or deficient. If deemed deficient, the Executive Officer shall identify the specific information required to make the application complete.

(c) Within 60 calendar days of the application being deemed complete, the Executive Officer shall issue or deny certification.

(d) Upon finding that a DG Unit meets the requirements of this article, the Executive Officer shall issue an Executive Order of Certification for the DG Unit. The Executive Officer shall provide a copy of the Executive Order of Certification to the Applicant.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94205. **Voluntary Certification.**

DG Units that do not emit air contaminants while operating may submit information requested in section 94204 (a)(1) through (3), and any information necessary to demonstrate that there are no emissions of air contaminants, to the Executive Officer for voluntary certification.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94206. **Labeling Requirements.**

(a) The Applicant shall affix a certification label on a visible location on each certified DG Unit.

(b) The certification label must be of durable material and be permanently attached to the DG Unit.

(c) The certification label must contain the year of the conforming emission standards, the fuel type used, and the number of the Executive Order of Certification.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94207. **Testing.**

(a) Sampling methodology used must conform to ARB testing procedures. Alternate or modified test methods must be submitted for approval by the Executive Officer.

(1) Testing shall be conducted in accordance with the following methods:

NO_x, CO, VOC and Oxygen:	ARB Test Method 100 (as adopted on July 28, 1997)
Gas Velocity and Flow Rate:	ARB Test Methods 1, 2, 3, and 4 (as adopted on July 1, 1999)

(b) California Public Utility Commission (CPUC) quality natural gas shall be used for certification testing. Other fuels may be used upon approval by the Executive Officer.

(c) Any additional control equipment or other devices that affect emissions shall be applied to the DG Unit and operated as marketed for the testing period.

(d) Testing parameters.

(1) Testing commences after the DG Unit has reached stable operation.

(2) Each run must be conducted for three power production loads: 50 percent of generator gross output, 75 percent of generator gross output, and 100 percent of generator gross output.

(A) A load bank may be used to establish the load.

(B) The DG Unit must be operated for a sufficient period of time to demonstrate stability in the emission reading at constant load and to ensure the collection of representative and quantifiable samples.

(C) A minimum of three valid test runs must be conducted. Each test is to be run consecutively. Justification for invalid test runs must be included in the test report.

(3) Generator output (MW-hr), based on gross output, shall be measured during each valid test run. A calibrated electric meter shall be used for the measurements. The meter shall be calibrated according to the American National Standards Institute's Code for Electricity Metering (ANSI C12-as of 1995).

(4) For each valid test run, the results for each tested load shall be averaged according to the following weighting factors:

50 percent load results shall be given 20 percent weight;
75 percent load results shall be given 50 percent weight; and
100 percent load results shall be given 30 percent weight.

The results of the three valid runs shall be arithmetically averaged and the emission rate (in lb/MW-hr) shall be calculated.

(5) Prior to commercial operation, each DG Unit shall be tested for NOx emissions at 100 percent load using a NOx analyzer that has been calibrated according to EPA CTM-022 (dated May, 1995) and approved by the Executive Officer. DG Units meeting the requirements of section 94203 (b) on or before January 1, 2003 will be exempt from this requirement.

(6) Alternate testing parameters may be used upon approval by the Executive Officer.

(7) Alternate testing parameters may be required by the Executive Officer.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94208. **Recordkeeping.**

(a) The Applicant must retain all information used for the certification application.

(b) Upon request of the Executive Officer, the Applicant will submit information to the ARB on the number and location of certified DG Units that have been sold in California.

(c) Upon request of the Executive Officer, the Applicant will submit to the ARB the serial numbers, emissions durability information, and information gathered in section 94207(d)(5) of certified DG Units sold in California.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94209. **Recertification.**

(a) Certification is valid for four years except where the test results for the initial certification of the DG unit does not meet the requirements in section 94203 (b). The certification for these DG units shall be valid until January 1, 2007.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94210. **Fees.**

(a) Fees shall be due and payable to the Executive Officer at the time an application is filed.

(b) DG Units subject to these regulations will be assessed a fee of $2500.00 for certification and/or recertification.

(c) DG Units seeking voluntary certification through section 94205 will be exempt from fees for certification.

(d) DG Units meeting the requirements of section 94203(b) on or before January 1, 2003 will be exempt from fees for certifying to the requirements in section 94203(a).

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94211. **Inspection.**

The Executive Officer, or an authorized representative of the Executive Officer, may periodically inspect manufacturers of DG Units for sale, lease, use or operation in California or, distributors, and retailers selling or leasing DG Units for use or operation in the state of California and conduct such tests as are deemed necessary to ensure compliance with these regulations. Failure of a manufacturer, distributor, or retailer to allow access for inspection purposes shall be grounds for suspension or revocation of certification.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94212. **Denial, Suspension or Revocation of Certification.**

(a) The Executive Officer for just cause may deny, suspend or revoke an Executive Order of Certification in any of the following circumstances:

(1) the Applicant has materially misrepresented the meaning, findings, effect or any other material aspect of the certification application, including submitting false or incomplete information in its application for certification regardless of the Applicant's personal knowledge of the falsity or incompleteness of the information;

(2) the test data submitted by the Applicant to show compliance with this regulation have been found to be inaccurate or invalid; or

(3) the certified unit has failed in-use to comply with the findings set forth in the Executive Order. For the purposes of this section, noncompliance with the certification may include, but is not limited to:

(A) a repeated failure to perform to the standards set forth in this article; or

(B) modification by the manufacturer of the DG Unit that results in an increase in emissions or changes the efficiency or operating conditions of such unit, without prior notice to and approval by the Executive Officer.

(b) A manufacturer may be denied certification or subject to a suspension or revocation action pursuant to this section based upon the actions of an agent, employee, licensee, or other authorized representative.

(c) The Executive Officer shall notify a manufacturer by certified mail of any action taken by the Executive Officer to deny, suspend or revoke any certification granted under this article. The notice shall set forth the reasons for and evidence supporting the action(s) taken. A suspension or revocation is effective upon receipt of the notification.

(d) A manufacturer may request that the suspension or revocation be stayed pending a hearing under section 94213. In determining whether to grant the stay, the hearing officer shall consider the reasonable likelihood that the manufacturer will prevail on the merits of the appeal and the harm the manufacturer will likely suffer if the stay is not granted. The Executive Officer shall deny the stay if the adverse effects of the stay on the public health, safety, and welfare outweigh the harm to the manufacturer if the stay is not granted.

(e) Once an Executive Order of Certification has been suspended pursuant to (a) above, the manufacturer must satisfy and correct all noted reasons for the suspension and submit a written report to the Executive Officer advising him or her of all such steps taken by the manufacturer before the Executive Officer will consider reinstating the certification.

(f) After the Executive Officer suspends or revokes an Executive Order of Certification pursuant to this section and prior to commencement of a hearing under section 94213, if the manufacturer demonstrates to the Executive Officer satisfaction that the decision to suspend or revoke the certification was based on erroneous information, the Executive Officer will reinstate the certification.

(g) Nothing in this section shall prohibit the Executive Officer from taking any other action provided for by law for violations of the Health and Safety Code.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94213. **Appeals.**

Any manufacturer whose application or certification has been denied, suspended, or revoked may request a hearing to review the action as provided herein.

(a) Hearing Procedure.

Except as provided for in section 94213(b) below, any appeal pursuant to this section 94213 shall be conducted in accordance with the Administrative Hearing Procedures for Petitions for Review of Executive Officer Decisions, Title 17 California Code of Regulations, Division 3. Chapter 1 Article 2, commencing with section 60055.1.

(b) Review by written submission.

(1) In lieu of the hearing procedure set forth in (a) above, a manufacturer may request that a review of the Executive Officer's decision be conducted by a hearing officer solely by written submission.

(2) A manufacturer may request a review of the Executive Officer's decision to deny, suspend or revoke a certification no later than 20 days from the date of issuance of the notice of the denial, suspension, or revocation. Such request shall include, at a minimum, the following:

(A) name of the manufacturer, the name, address and telephone number of the person representing the manufacturer and a statement signed by a senior officer of the manufacturer warranting that the representative has full authority to bind the manufacturer as to all matters regarding the appeal;

(B) copy of the Executive Order granting certification and the written notification of denial;

(C) a statement of facts and explanation of the issues to be raised setting forth the basis for challenging the denial, suspension, or revocation (conclusory allegations will not suffice) together with all documents relevant to those issues; and

(D) the signature of the representative named in (A) above.

(3) Upon receipt of a request for review, the request shall be referred to the administrative hearing office of the state board for assignment of a hearing officer.

(4) Within 15 days of appointment of a hearing officer:

(A) ARB staff shall submit a written response to the manufacturer's submission and documents in support of the Executive Officer's action no later than 10 days after receipt of the manufacturer's submission;

(B) within 7 days of receipt of the ARB response, the manufacturer may submit one rebuttal statement which shall be limited to the issues raised in the ARB rebuttal;

(C) if the manufacturer submits a rebuttal, ARB staff may, within 7 days of receipt of the manufacturer's rebuttal, submit one rebuttal statement which shall be limited to the issues raised in the manufacturer's rebuttal; and

(D) the hearing officer shall receive all statements and documents and render a written decision. The hearing officer's decision shall be mailed to the manufacturer no later than 60 working days after the final deadline for submission of papers.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

94214. **Penalties.**

In addition to suspension or revocation of certification as provided in section 94212, ARB may seek penalties under Health and Safety Code Division 26, Part 4., Chapter 4, Article 3 commencing with section 42400, for any violation of these regulations.

NOTE: Authority cited: Sections 39600, 39601 and 41514.9 Health and Safety Code. Reference: Section 41514.9 Health and Safety Code.

Appendix C

Summary of District Permit Exemptions for Equipment that May Be Used for Electrical Generation

Distributed Generation - SB 1298

Summary of District Permit Exemptions for Equipment that may be Used for Electrical Generation

District	Internal Combustion Engine Exemptions	Turbine Engine Exemptions	Miscellaneous Exemptions
Amador	<1000 CID (applies to diesel or gasoline fired engines. Natural gas and LPG fired engines are exempt.) [Rule 402]	None ID'd	1) Equipment used exclusively in connection with a dwelling (2-family max); 2) other sources <1 tpy [Rule 402]
Antelope Valley	1) <50 HP; 2) test cells and test stands where diesel use <800 gallons/year; and 3) engines used exclusively for training at teaching institutes. [Rule 219]	heat input rating <2,975,000 BTU/hr [Rule 219]	Equipment used exclusively in connection with a dwelling (4-family max) where equipment is used solely owner or occupant [Rule [219]
BAAQMD	1) <50 HP; 2) research or teaching facilities; 3) portable & standby ICEs operating <200 hrs/year plus an additional 100 hrs/yr for maintenance at any facility; 4) ICEs mounted on mobile or marine equipment to provide both propulsion and mechanical or electrical power for ancillary operations. [Rule 2-1]	1) <50 HP; 2) research and teaching facilities [Rule 2-1]	1) Source emissions <10 lb/day for certain pollutants or <150 lb/yr for combined pollutants; 2) any source that is deemed by the APCO to be equivalent to other exempted sources. [Rule 2-1]
Butte	1) Any continuous-duty engine rated at 250HP or less, (except diesel-fueled) to operate less than 200hrs/yr; 2) 50HP or less; 3) engines used exclusively for fire fighting or flood control; 4) lab engines used in research testing [Board Policy]	None ID'd	1) Equipment used exclusively in connection with a dwelling (2-family max); 2) other sources deemed of minor significance by APCO [Rule 404]
Calaveras	<1000 CID [Rule 402]	None ID'd	1) Equipment used exclusively in connection with a dwelling (2-family max); 2) other sources <1 tpy [Rule 402]
Colusa	≤ 50 HP [Rule 2.36]	1. Emergency Units operating <200 hrs/yr. 2) units rated less than 4 MW operating less than 877 hrs/yr. [Rule 2.41]	1) Equipment used exclusively in connection with a dwelling (2-family max); 2) sources deemed of minor significance by the APCO. [Rule 3.3]
El Dorado	<50 HP; HP of engines used in same process are added together. [Rule 501]	<3 MMBTU/hr heat input rating; BTUs of engines used in same process are added together [Rule 501]	1) Equipment used exclusively in connection with a dwelling (4-family max) where equipment is used solely owner or occupant; 2) source emitting <2 lb/day of any pollutants without controls. [Rule 501]

District	Internal Combustion Engine Exemptions	Turbine Engine Exemptions	Miscellaneous Exemptions
Feather River	No size threshold identified. [Rule 4.3]	None ID'd	1) Equipment used exclusively in connection with a dwelling (2-family max); 2) sources with uncontrolled emissions <2 lb/day. [Rule 4.3]
Glenn	No size threshold identified. [Article III, Section 57]	None ID'd	1) Equipment used exclusively in connection with a dwelling (2-family max); 2) sources deemed of minor significance by the APCO. [Article III, Section 57]
Great Basin Unified	All piston type engines: uncontrolled, potential to emit of less than - 250 lb/day of any criteria pollutant (except CO and PM), 250 lb/day of TSP, and 80 lb/day of PM10. [Rule 201 and 209-A.B.2]	None ID'd	Equipment used exclusively in connection with a dwelling (4-family max) where equipment is used solely owner or occupant. [Rule 201]
Imperial	1) <50 HP, all engines at a facility are additive. [Rule 202]	<3MM BTU/hr heat input, all engines at facility are additive. [Rule 202]	1) Uncontrolled emissions of affected pollutants <2 lb/day; 2) otherwise exempt equipment requires a permit if part of process that requires a permit. [Rule 202]
Kern	1) <50 HP; 2) equipment operated 45 days or less at one source, if emissions <2 tpy of any air contaminant with APCO approval. [Rules 202 & 427]	<3MM BTU/hr heat input. [Rules 202 & 425]	1) Equipment operated 45 days or less at one source if emissions <2 tpy of any air contaminant with APCO approval. 2) other sources emitting <10 lb/day, 180 lb/qtr, and emissions do not interfere with Air Quality Attainment Plan with APCO approval; 3) certain research operations with APCO approval. [Rules 202 & 202.1]
Lake	No size threshold identified. [Chapter IV, Article IV, Section 640	None ID'd	None ID'd
Lassen	All piston type engines, except those used to power stationary sources or air pollution equipment. [Section 2:1]	None ID'd	Equipment used exclusively in connection with a dwelling (4-family max).
Mariposa	1) <1000 CID if fired with diesel or gasoline; or 2) any ICE fired with natural gas or LPG. [Section 402]	None ID'd	1) Equipment used exclusively in connection with a dwelling (2-family max); 2) other sources <1 tpy [Section 402]
Mendocino	No size threshold identified. [Section 200]	None ID'd	1) Equipment used exclusively in connection with a dwelling (4-family max); 2) other sources deemed insignificant by the APCO

District	Internal Combustion Engine Exemptions	Turbine Engine Exemptions	Miscellaneous Exemptions
Modoc	No size threshold identified. [Section 2.2]	None ID'd	1) Equipment used exclusively in connection with a dwelling (4-family max); 2) other sources deemed insignificant by the APCO [Section 2.2]
Mojave Desert	1) <100 HP; HP of engines used in same process are added; 2) ICEs used exclusively for training at educational institutions. [Rules 219 & 1160]	1) <3 MMBTU/hr; HP of engines used in same process are added together; 2) turbines that qualify as TSE, with portable equipment registration. [Rule 219]	1) Equipment used exclusively in connection with a dwelling (4-family max); 2) general combustion source <2 MMBTU/hr gross, if fired exclusively with natural gas, LPG, or combination thereof. Ratings of sources used in same process are added together. [Rule 219]
Monterey Bay Unified	1) single ICE: <100 HP; 2) multiple ICEs at a source: any individual ICE <50 HP or aggregate of ICEs <100 HP 3) emergency generators (see limits). [Section 201]	None ID'd	Equipment used exclusively in connection with a dwelling (4-family max). [Section 201]
North Coast Unified	<50 HP [Board Policy]	None ID'd	1) Equipment used exclusively in connection with a dwelling (4-family max); 2) other sources deemed insignificant by the APCO [Rule 1-2-200]
Northern Sierra	1) Any ICE fired with natural gas, LPG, or; 2) <1000 CID fired with diesel or gasoline. [Rule 402]	None ID'd	1) Equipment used exclusively in connection with a dwelling (2-family max); 2) other sources emitting <1 tpy. [Rule 402]
Northern Sonoma	No size threshold identified. (exemption not applicable if subject to NSR) [Rule 1-2-200]	None ID'd	1) Equipment used exclusively in connection with a dwelling (4-family max); 2) other sources deemed insignificant by the APCO [Rule 1-2-200]
Placer	<50 HP; HP of engines used in same process are added together [Rule 501]	<3 MMBTU/hr heat input rating; heat ratings used in same process are added together. [Rules 501 & 250]	1) Combustion equipment: <1 MMBTU/hr gross, if fired exclusively by natural gas, LPG, or combination thereof. Ratings of sources used in same process are added together; 2) equipment used exclusively in connection with a dwelling (4-family max); 3) other equipment authorized by the APCO and which would emit <2 lb/24-hr period, if uncontrolled. [Rule 501]

District	Internal Combustion Engine Exemptions	Turbine Engine Exemptions	Miscellaneous Exemptions
Sacramento Metropolitan	<50 HP; HP of engines used in same process are added together. [Rules 201 & 412]	<3 MMBTU/hr heat input rating; heat ratings used in same process are added together. [Rule 201]	1) Combustion equipment: <1 MMBTU/hr gross, if fired exclusively by natural gas, LPG, or combination thereof. Ratings of sources used in same process are added together; 2) equipment used exclusively in connection with a dwelling (4-family max); 3) other equipment authorized by the APCO and which would emit <2 lb/24-hr period, if uncontrolled. [Rule 201]
San Diego	1) Single ICE: <50 HP 2) engines used for educational training; 3) portable construction cranes that are routinely dismantled and transported to non-contiguous locations for temporary use; 4) ICEs mounted on mobile or marine equipment to provide primarily propulsion but also mechanical or electrical power for ancillary operations; portable ICE's used exclusively with military TSE. [Rules 11, 69.4 & 69.4.1]	1) Maximum output < 0.3 mw; or 2) Maximum input < 1,000,000 BTU/hr. [Rules 11, 69.3 & 69.3.1]	1) No specific exemption shall apply if emissions are >100 lb/day of criteria pollutants (PM10, NOx, VOC, SOx, CO, or Pb); 2) No exemption is allowed if toxic emissions exceed Rule 1200 standards; 3) other cumbustion equipment (excludes boilers, process heaters, steam generators, engines or gas turbines): <20 MMBTU/hr gross heat input, if fired exclusively with natural gas or LPG; 4) equipment used exclusively in connection with a dwelling (4-family max); 5) other sources deemed insignificant by the APCO. [Rule 11]
San Joaquin Valley Unified	<50 HP. [Rules 2020 & 4701]	<3 MMBTU/hr heat input rating. [Rules 2020 & 4703]	[Rule 4301]
San Luis Obispo	1) <50 HP; HP of engines used in same process are added together; 2) ICEs used solely for standby power and meeting operating limits. [Rules 201 & 431]	<3 MMBTU/hr heat input rating; ratings of turbines used in same process are added together [Rule 201]	1) Equipment emitting uncontrolled emissions <2 lb/day; 2) combustion equipment <2 MMBTU/hr gross, if fired exclusively with natural gas, LPG, or combination thereof. Ratings of equipment used in same process are added together [Rule 201]

District	Internal Combustion Engine Exemptions	Turbine Engine Exemptions	Miscellaneous Exemptions
Santa Barbara	1) Single: <100 HP, multiple: <500 HP (counting engines >20 HP); 2) construction operations activities as defined under Rule 102, if overall emissions <25 TPY (and then offsets are required); 3) < 50 HP: a) military TSE; b) power temperature and humidity control systems associated with the transport of satellites and space launch equipment; and c) cargo handling equipment permanently affixed to motor vehicles for space launch support; 4) drilling equipment used in STW and OCS, if emissions <25tpy per source; 5) seasonal (<18 days) amusement rides. [Rules 202 & 333]	<3 MMBTU/hr heat input rating [Rule 202]	1) Temporary equipment where aggregate emissions <1 ton (except CO: <5 ton) and <60 day/12 month period, and equipment is not part of existing source operations or not replacing equipment under breakdown condition; 2) any source whose uncontrolled emissions <1 tpy, if meeting certain other conditions; 3) any collection of otherwise exempt sources at a facility with aggregate emissions >25 tpy is <u>not</u> exempt; 4) combustion equipment <5 MMBTU/hr, if fired exclusively with natural gas, LPG, or combination thereof. Ratings of equipment used in same process are added together; 5) combustion equipment <1MMBTU/hr does not count toward 25 tpy aggregate, if fired with clean fuel. [Rule 202]
Shasta County	1) <50HP 2) engines operated directly and exlusively for agricultural operations. 3) operating less than 200 hrs/yr 4) gas turbine engines. [Rules 2:5 & 3.28]	None ID'd	1) Home use appliances; 2) dryers for wood and wood products; 3) any source deemed insignificant by the APCO. [Rule 2:5]
Siskiyou	No size threshold identified. [Rule 2.2]	None ID'd	1) Equipment used exclusively in connection with a dwelling (4-family max); 2) other sources deemed insignificant by the APCO [Rule 2.2]
SCAQMD	1) <50 HP; 2) test cells and test stands for testing engines where diesel use <800 gals/yr; and 3) engines used exclusively for training at educational institutions. [Rules 219, 1110.1 & 1110.2]	1) <2,975,000 BTU/hr heat input rating; 2) turbines qualified as military TSE. [Rules 219 & 1134]	1) Equipment used exclusively in connection with a dwelling (4-family max); 2) natural gas and crude oil production equipment used exclusively as water boilers, hydrocarbon heaters that have heat input rating <2 MMBTU/hr and fired exclusively with natural gas, LPG (<10 ppm hydrogen sulfide) or combination thereof. [Rule 219]

District	Internal Combustion Engine Exemptions	Turbine Engine Exemptions	Miscellaneous Exemptions
Tehama	1) <50 HP; 2) any engine used for: a) emergency purposes; b) agriculture operations; c) non-emergency purposes <200 hrs/yr; d) fire fighting or flood control; e) laboratory engines for research and testing. [Rules 2:4 & 4:34]	1) <0.3 MW; 2) emergency units <200 hrs/yr; 3) <4 MW <877 hrs/yr. [Rules 2:4 & 4:37]	Permit & registration may not be required for the following: 1) Equipment used exclusively in connection with a dwelling (2-family max); 2) fuel burning equipment utilizing natural gas, LPG, or both; 3) other sources deemed insignificant by the APCO on a case-by-case basis. [Rule 2:4]
Tuolumne	1) Any ICE fired with natural gas or LPG, or; 2) <1000 CID if fired with diesel or gasoline. [Rule 402]	None ID'd	1) Equipment used exclusively in connection with a dwelling (2-family max); 2) other sources emitting <1 tpy. [Rule 402]
Ventura	1) <50 HP 2) emergency (maintenance limited to 50 hrs/yr) [Rules 23.D.6 and D.7 & 74.9]	50 HP [Rules 23 & 74.23]	No misc.permit exemptions.
Yolo-Solano	1) <50 HP; HP of engines used in same process are added together. [Rule 3.2]	<3 MMBTU/hr heat input rating; ratings of turbines used in same process are added together. [Rule 3.2]	1) Equipment used exclusively in connection with a dwelling (4-family max); 2) other sources deemed insignificant by the APCO and emitting <2 lb/day; [Rule 3.2]

Appendix D

Select Gaseous Emissions Data from the SMUD Capstone 30 Microturbine

California Environmental Protection Agency

Air Resources Board

SOURCE TEST REPORT

Select Gaseous Emissions Data from the SMUD Capstone 30 Microturbine

MONITORING AND LABORATORY DIVISION
ENGINEERING AND CERTIFICATION BRANCH

FILE NO: T-01-040

DATE: September 6, 2001

APPROVED:

David F. Todd, Project Engineer
Testing Section

______, Manager
Testing Section

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ACKNOWLEDGEMENTS

The project leader was David Todd and the field engineer was Oscar Lopez with the ARB. Instrument technicians were Ken Lewis (lead), LaJuan Taylor, and Ron Barros with the ARB. Assistance was provided by H.I. "Bud" Beebe with Sacramento Municipal Utilities District. ARB Stationary Source Division assistance was provided by Grant Chin and Kitty Martin.

California Environmental Protection Agency
AIR RESOURCES BOARD
Monitoring and Laboratory Division

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California Environmental Protection Agency
AIR RESOURCES BOARD
Monitoring and Laboratory Division

Select Gaseous Emissions Data from the SMUD Capstone 30 Microturbine

I. INTRODUCTION

At the request of the Air Resources Board's (ARB) Stationary Source Division (SSD), staff of the Engineering and Certification Branch (ECB) collected gaseous emissions data from a Capstone Turbine Corporation's Model 30 MicroTurbine™™ (Model 30) generator. The Model 30, located behind the Sacramento Municipal Utilities District (SMUD) headquarters at 6301 S Street, is operated by SMUD as part of their distributed power generation network. Exhaust emissions data were collected from the Model 30 on June 10, 2001, at loads of 50%, 75%, and 100% of capacity while operating on natural gas.

II. PROCESS DESCRIPTION

In a gas turbine, a rotor compresses air that is then forced into a combustor where it mixes with natural gas and is ignited. This causes the gases to heat and expand. As the heated gases exit the combustor, they are directed towards a turbine forcing the turbine to rotate. The rotating turbine creates shaft horsepower to operate a generator thereby producing electricity. The Model 30 is a high efficiency gas turbine generator designed to produce 30kW of electrical net output.

As with any gas turbine, performance is dependent upon ambient temperature and pressure conditions. According to the manufacturer, as the inlet temperature of the Model 30 increases above 15° C (59° F) the maximum output decreases. For this reason, and based on the SMUD operator's experience, 28 kW was set as the 100 percent load. Additionally, SSD staff requested that emissions sampling be performed when the inlet air temperature was 15° C (59° F) or less.

III. SAMPLING METHODS AND LOCATIONS

Gaseous exhaust emissions were analyzed and their concentrations determined in accordance with ARB Stationary Source Test Method 100, "Procedures for Continuous Gaseous Emissions Stack Sampling." Emissions determined included oxygen (O2), carbon dioxide (CO2), carbon monoxide (CO), total hydrocarbons (THC), and oxides of nitrogen (NOx). Table III-1 lists the make, model and type of gas analyzers used during this source test. Data from all analyzers were collected on strip charts and read by ECB staff to determine the concentrations of gaseous emissions.

Table III-1
Method 100 Emissions Sampling Equipment

Emissions Parameter	Instrument Information		
	Manufacturer	Model	Type
O2	Rosemont Analytical	755 R	Paramagnetic
CO2	Horiba	VIA-510	NDIR
CO	TECO	48	NDIR
THC	Beckman	400	FID
NOx	TECO	42H	Chemiluminescence

Stack flows were determined with ARB Stationary Source Test Method 1 - Velocity Traverse, Method 2 - Stack Velocity and Flow Rate, Method 3 - Dry Molecular Weight, and Method 4 - Moisture Content.

To determine stack flows and collect samples for analysis, it was necessary to increase the length of the exhaust stack for the Model 30. ECB staff fabricated a stack extension that was 'slip-fitted' over the existing exhaust outlet. The stack extension was 6 inches in diameter and 84 inches in length. Pitot tube measurements were made at 48 inches downstream (8 diameters) and samples were collected at 72 inches downstream (12 diameters). The stack extensions were fabricated with two sets of sampling ports, each 90° apart, at both 48 inches and 72 inches downstream from the source.

A traverse performed with the gas analyzers sample probe prior to testing indicated that single point gaseous sampling was permissible per ARB Method 100. Full velocity traverses were performed at 100 percent, 75 percent, and 50 percent loadings.

Additionally, the Model 30 has a dedicated Roots positive displacement volume meter to measure the volume of natural gas fuel used by the Model 30. Staff periodically collected data from this meter during testing to monitor fuel flow. Fuel flow and EPA F-factors (see EPA Test Method 19) may be used to estimate stack flow.

IV. QUALITY ASSURANCE

All gas analyzers were calibrated immediately before and after source testing as required by ARB Method 100. Pre- and post-test sampling system bias checks were performed on all analyzers. Additionally, all instruments were within zero and calibration post-test drift requirements.

The Method 5 sampling console used for stack velocity and moisture determinations was calibrated per ARB Method 5 in March 2001. The Type S pitot tube used for stack velocity determinations met the required specifications for a baseline coefficient of 0.84 as specified in ARB Method 2. The pitot tube and console assembly passed leak checks before and after the velocity determinations. The moisture train assembly also passed leak checks before and after sampling for water vapor.

V. TEST RESULTS

Test results are shown in Appendix A. Additionally, Appendix B contains copies of the Field Data Sheets, Appendix C copies of the continuous analyzer's strip charts, and Appendix D contains data collected by SMUD from the Model 30 during sampling at 100 percent, 75 percent, and 50 percent loadings.

In accordance with ARB Method 100, the range of each analyzer is selected such that the sampled gas concentrations are between 10 and 95 percent of the range of each specific instrument. Due to SSD's request to perform emissions sampling when the Model 30's inlet temperature was 59° F or less, analyzer ranges were not changed due to time constraints. Changing analyzer ranges requires time for additional calibrations of the instruments. Therefore, in some cases these limits were exceeded. Where this occurred the data are reported in parenthesis.

Table IV-1 presents a summary of the Model 30 power output, inlet air temperatures, and concentrations for NOx, CO, and THC as measured and as corrected to 15% oxygen. As indicated in Table IV-1, average inlet temperatures remained below 59° F for Test Runs 1 and 2. Average inlet temperatures for the 3 power loads for Run 3 ranged from 60° F to 63° F.

Table IV-2 presents a summary of average mass emissions in pounds per cubic foot (lb./cu.ft.) for the three power loadings.

Table IV-3 presents a summary of mass emissions in pounds per hour (lb/hr) and pounds per megawatt-hour (lb/MW-hr).

Table IV-4 presents measured concentrations in 5% power load intervals between 50% and 100% power loads and 25% power load. It should be noted that inlet air temperatures during this portion of the test were greater than 59° F.

Table IV-1
Test Results

Gaseous Concentrations at 100%, 75%, and 50% Loads

Power Load, (%)	Capstone, Output (kilowatts)	Inlet Air Temp. (deg. F)	Measured Concentrations					Concentrations Corrected to 15% O2		
			O2, (%)	CO2, (%)	NOx, (ppm)	THC (as C3), (ppm)	CO, (ppm)	NOx, (ppm)	THC (as C3), (ppm)	CO, (ppm)
100	28	58	18.3	1.4	(0.73)	(<1)	(3.7)			
100	28	58.5	18.3	1.5	(0.83)	(<1)	(3.4)			
100	28	60	18.3	1.5	(0.76)	(<1)	(3.2)			
Average	28		18.3	1.5	(0.77)	(<1)	(3.4)	(1.8)	(<2)	(7.7)
75	21	58	18.6	1.3	(0.26)	12	87			
75	21	58	18.6	1.3	(0.66)	11	89			
75	21	61	18.6	1.3	(0.33)	11	79			
Average	21		18.6	1.3	(0.42)	11	85	(1.1)	28	220
50	14	57	19.0	1.1	19	(3)	43			
50	14	56.5	19.0	1.1	19	(3)	35			
50	14	63	18.9	1.1	19	(3)	38			
Average	14		19	1.1	19	(3)	42	(59)	(9.3)	130

( ) - Numbers in parenthesis indicate data outside 10 to 95 percent of the analyzers full scale range.

Table IV-2
Test Results

Mass Emissions for Average Concentrations at 100%, 75%, and 50% Power Loads

Power Load, (%)	Capstone Output (kilowatts)	Measured Concentrations			Mass Emissions		
		NOx, (ppm)	THC (as C3), (ppm)	CO, (ppm)	NOx, (lb/cu.ft.)	THC (as C3), (lb/cu.ft.)	CO, (lb/cu.ft.)
100	28	(0.77)	(<1)	(3.4)	(8.8E-08)	(<1.1E-07)	(2.5E-07)
75	21	(0.42)	11	85	(4.8E-08)	1.3E-06	6.2E-08
50	14	(19)	(3)	42	(2.2 E-06)	(3.4E-07)	3.1 E-06

Standard conditions are 68 deg. F and 29.92 in. Hg.

( ) - Numbers in parenthesis indicate data outside 10 to 95 percent of the analyzers full scale range.

Table IV-3
Test Results

Mass Emissions in lb/hr and lb/MW-hr. at 100%, 75%, and 50% Loads

Power Load, (%)	Capstone, Output, (kilowatts)	Exhaust Flow, (dscfm)	Mass Emissions NOx, (lb/hr)	Mass Emissions THC (as C3), (lb/hr)	Mass Emissions CO, (lb/hr)	Mass Emissions NOx, (lb/MW-hr)	Mass Emissions THC (as C3), (lb/MW-hr)	Mass Emissions CO, (lb/MW-hr)
100	28	571	(0.003)	(<0.0039)	(0.0085)	(0.11)	(<0.14)	(0.30)
75	21	495	(0.0014)	0.037	0.18	(0.068)	1.8	8.7
50	14	417	(0.076)	(0.0086)	0.076	(3.9)	(0.61)	5.5

Standard conditions are 68 deg. F and 29.92 in. Hg.

( ) - Numbers in parenthesis indicate data outside 10 to 95 percent of the analyzers full scale range.

Table IV-4

Concentrations at 5% Intervals from 50% to 100% and 25% Power Load

Power Load, (%)	Capstone Output (kilowatts)	Measured Concentrations				
		O2, (%)	CO2, (%)	NOx, (ppm)	THC (as C3), (ppm)	CO, (ppm)
50	14.0	18.9	1.4	19	(3)	(8.4)
55	15.4	18.8	1.2	19	(2)	23.8
60	16.8	18.8	1.2	(>20)	(<1)	15.6
65	18.2	18.8	1.3	(>20)	(<1)	10.8
70	19.6	18.8	1.3	(>20)	(<1)	(8.3)
75	21.0	18.7	1.3	(0.79)	(8)	66.7
80	22.4	18.5	1.4	(0.69)	(4)	40.6
85	23.8	18.5	1.4	(0.65)	(2)	21.4
90	25.2	18.7	1.4	(0.81)	(<1)	(8.9)
95	26.6	18.4	1.4	(0.84)	(<1)	(3.8)
100	27(max.)	18.5	1.4	(0.84)	(<1)	(3.1)
25	7	17.7	0.95	16.0	60	(>100)

( ) - Numbers in parenthesis indicate data outside 10 to 95 percent of the analyzers full scale range.

APPENDIX A

Calculated Results

Appendix A-1

Calculated Results (lb/cu.ft., lb/hr, and lb/MW-hr) at Different Concentrations for Different Concentrations at 100%, 75%, and 50% Power Loads

lb/cu.ft. = + ppm * mole. Wt. *0.000000002597
lb/hr = + lb/cu.ft. *scfm * 60 min/hr
lb/ mW*hr = + 1000kW/MW * lb/hr / (kW)

Mole. Wt.
NOx = NO2 = 44
CO = 28
THC as C3H8 = 44

Flows by Load, dscfm
100% = 571
75% = 495
50% = 417

Compound	Load, % %	Avg. Conc. ppm	Mole. Wt.	Emission, lb/cu.ft.	Flow, dscfm	Emission, lb/hr	Power Out, kW	Emissions lb./MW-hr
NOx	100	2	44	2.29E-07	571	7.83E-03	28	0.280
NOx	100	0.77	44	8.8E-08	571	3.01E-03	28	0.108
THC	100	10	44	1.14E-06	571	3.91E-02	28	1.400
THC	100	1	44	1.14E-07	571	3.92E-03	28	0.140
CO	100	10	28	7.27E-07	571	2.49E-02	28	0.890
CO	100	3.4	28	2.47E-07	571	8.47E-03	28	0.303
NOx	75	2	44	2.29E-07	495	6.79E-03	21	0.323
NOx	75	0.42	44	4.8E-08	495	1.43E-03	21	0.068
THC	75	11	44	1.26E-06	495	3.73E-02	21	1.778
CO	75	85	28	6.18E-06	495	0.184	21	8.742
NOx	50	18	44	2.06E-06	417	5.15E-02	14	3.676
NOx	50	19	44	2.17E-06	417	5.43E-02	14	3.880
THC	50	10	44	1.14E-06	417	0.02859	14	2.042
THC	50	3	44	3.43E-07	417	8.58E-03	14	0.612
CO	50	42	28	3.05E-06	417	7.64E-02	14	5.458

Table A-2
Capstone Turbine Emission Concentrations

Sample Time (min)	Load Capacity (%)	Concentration As Found				Actual C_{gas} Concentration		Concentration @ 15% O2	
		O2 (0-25%)	CO2 (1-10%)	NOx (0-20ppm)	CO (0-100ppm)	NOx (ppm)	CO (ppm)	NOx (ppm)	CO (ppm)
37	100	18.3	1.44	0.69	3.7	(0.73)	(3.7)	1.65	8.4
30	75	18.62	1.3	0.25	87	(0.26)	87.0	0.68	225.1
30	50	19	1.1	18.23	43.17	(19.22)	43.2	59.69	134.1
30	50	19	1.1	18.36	44.68	(19.36)	44.7	60.12	138.7
30	75	18.6	1.3	0.63	88.63	(0.66)	88.6	1.70	227.4
30	100	18.3	1.45	0.79	3.43	(0.83)	(3.4)	1.89	7.8
28	100	18.3	1.45	0.72	3.21	(0.76)	(3.2)	1.72	7.3
38	75	18.62	1.3	0.31	79.2	(0.33)	79.2	0.85	204.9
24	50	18.9	1.12	17.9	38	18.87	38.0	55.68	112.1

( ) - Numbers in parenthesis indicate data outside 10 to 95 percent of the analyzers full scale range.

FORMULAS

POLLUTANT CONCENTRATION

$C_{gas} = (C_{avg} - C_o) * C_{cal}/(C_{bal} - C_o)$ Equation

Where:

C_{gas} = Effluent gas concentration, ppm or % by volume

C_{avg} = Average gas concentration indicated by gas analyzer, ppm or % by volume

C_o = Average of initial (cib and final (cfb) system bias responses for zero gas, ppm or % by volume

C_{cal} = Actual concentration of the calibration gas used for the bias check, ppm or % by volume

C_{bal} = Average of initial (cib and final (cfb) sampling system bias responses for calibration gas, ppm or % by volume

NOx ppm	
C_o	0
C_{cal}	18.4
C_{bal}	17.45

CO ppm	
C_o	0
C_{cal}	60.7
C_{bal}	60

Corrrection to 15% O2 (using O2 in air as 20.9%)

$C_{15\%O2} = C_{dgas} * [(20.9-15)/(20.9-\%O_2 \text{ during test})]$ Equation

Table A-3
Capstone Turbine Emission Concentrations

Sample Time (min)	% Load Capacity	Concentration As Found				Actual C_{gas} Concentration		Concentration @ 15% O2	
		O2 0-25%	CO2 0-10%	NOx 0-20ppm	CO 0-100ppm	NOx 0-20ppm	CO 0-100ppm	NOx 0-20ppm	CO 0-100ppm
9	55	18.8	1.19	18.28	23.75	19.28	23.8	54.15	66.7
10	60	18.75	1.2	> 20	15.6	> 20	15.6	> 20	42.8
10	65	18.75	1.25	> 20	10.75	> 20	10.8	> 20	29.5
10	70	18.75	1.29	> 20	8.3	> 20	8.3	> 20	22.8
15	75	18.7	1.3	0.75	66.67	0.79	66.7	2.12	178.8
9	80	18.5	1.35	0.65	40.6	0.69	40.6	1.68	99.8
9	85	18.5	1.37	0.62	21.38	0.65	21.4	1.61	52.6
12	90	18.7	1.4	0.77	8.9	0.81	8.9	2.18	23.9
9	95	18.4	1.42	0.8	3.8	0.84	3.8	1.99	9.0
8	100	18.5	1.44	0.8	3.13	0.84	3.1	2.07	7.7
16	25	17.65	0.95	15.2	> 100	16.03	> 100	29.10	> 100

FORMULAS

POLLUTANT CONCENTRATION

$C_{gas} = (C_{avg} - C_o) * C_{cal}/(C_{bal} - C_o)$ Equation

Where:

C_{gas} = Effluent gas concentration, ppm or % by volume
C_{avg} = Average gas concentration indicated by gas analyzer, ppm or % by volume
C_o = Average of initial (cib and final (cfb) system bias responses for zero gas, ppm or % by volume
C_{cal} = Actual concentration of the calibration gas used for the bias check, ppm or % by volume
C_{bal} = Average of initial (cib and final (cfb) sampling system bias responses for calibration gas, ppm or % by volume

NOx ppm	
C_o	0
C_{cal}	18.4
C_{bal}	17.45

CO ppm	
C_o	0
C_{cal}	60.7
C_{bal}	60

Corrrection to 15% O2 (using O2 in air as 20.9%)

$C_{15\%O2} = C_{dgas} * [(20.9-15)/(20.9-\%O_2 \text{ during test})]$ Equation

MONITORING & LABORATORY DIVISION
ENGINEERING & CERTIFICATION BRANCH

FIELD DATA SHEET

FILE NO.:	T-01-040	PITOT TUBE FACTOR (Cp)	0.84
PROJECT NAME:	SMUD/Capstone 30	PROBE TIP DIA, in. (Dn)	N/A
RUN NO.:	100% load	STACK DIA, inches	6.0
LOCATION	Turbine Stack	STATIC PRESS, "H2O (Ps)	-0.69
BAR. PRESS, "Hg(Pb)	29.91	METER TEMP, F	60

SAMPLE POINT	t CLOCK TIME min.	Vm DRY GAS METER cu. ft.	dP PITOT PRESS. in. H2O	dH ORIFICE PRESS. (ACTUAL) in. H2O	Ts STACK TEMP. F
START	0	0	---	---	---
1E			1.1		528
2E			1.4		529
3E			1.6		529
4E			1.6		527
1W			1.3		527
2W			1.4		528
3W			1.7		530
4W			1.7		528
					528
	t= 0	Vm= 0.00	/dP avg.= 1.212	dH avg.= ERR	Ts avg.= 528.2

TEST SUMMARY AND RESULTS (FOR FIELD DATA RECORD)

FILE NO.:	T-01-040
PROJECT NAME:	SMUD/Capstone 30
RUN NO.:	100% load

SUMMARY OF TEST DATA

Barometric Pressure (Pb):	29.91	inches Hg
O2 in Stack (%O2):	18.3	percent
CO in Stack (%CO):	0.00	percent
CO2 in Stack (%CO2):	1.45	percent
N2 in Stack (%N2):	80.25	percent
Pitot Tube Factor (Cp)	0.84	
Avg. of Sqrt. of Pitot Press. (/dP avg):	1.21	/(inches H2O)
Stack Temperature (Ts)	988	deg. R
Static Pressure	-0.69	inches H2O
Absolute Stack Pressure (Ps)	29.86	inches Hg
Stack Dimensions	6.0	inches dia.
Stack Area (As)	0.196	square feet

CALCULATED RESULTS

Water Vapor in Stack (Bws):	2.75	percent by volume
Stack Gas Molecular Wt, Dry (Md):	28.96	lb/lbmole
Stack Gas Molecular Wt, Wet	28.66	lb/lbmole
Stack Gas Velocity (Vs):	93.50	feet/second
Stack Gas Flow Rate (Qs):	571	DSCFM(68 deg.F)

MONITORING & LABORATORY DIVISION
ENGINEERING & CERTIFICATION BRANCH

FIELD DATA SHEET

FILE NO.:	T-01-040	PITOT TUBE FACTOR (Cp)	0.84
PROJECT NAME:	SMUD/Capstone 30	PROBE TIP DIA, in. (Dn)	N/A
RUN NO.:	75% load	STACK DIA, inches	6.0
LOCATION	Turbine Stack	STATIC PRESS, "H2O (Ps)	-0.33
BAR. PRESS, "Hg(Pb)	29.91	METER TEMP, F	60

SAMPLE POINT	t CLOCK TIME min.	Vm DRY GAS METER cu. ft.	dP PITOT PRESS. in. H2O	dH ORIFICE PRESS. (ACTUAL) in. H2O	Ts STACK TEMP. F
START	0	0	—	—	—
1E			0.93		493
2E			1.1		486
3E			1.1		486
4E			1.1		484
1W			0.93		486
2W			1.1		486
3W			1.1		498
4W			1.1		489
					490
	t= 0	Vm= 0.00	/dP avg.= 1.028	dH avg.= ERR	Ts avg.= 488.7

TEST SUMMARY AND RESULTS (FOR FIELD DATA RECORD)

FILE NO.:	T-01-040
PROJECT NAME:	SMUD/Capstone 30
RUN NO.:	75% load

SUMMARY OF TEST DATA

Barometric Pressure (Pb):	29.91	inches Hg
O2 in Stack (%O2):	18.6	percent
CO in Stack (%CO):	0.00	percent
CO2 in Stack (%CO2):	1.3	percent
N2 in Stack (%N2):	80.10	percent
Pitot Tube Factor (Cp)	0.84	
Avg. of Sqrt. of Pitot Press. (/dP avg):	1.03	/(inches H2O)
Stack Temperature (Ts)	949	deg. R
Static Pressure	-0.33	inches H2O
Absolute Stack Pressure (Ps)	29.89	inches Hg
Stack Dimensions	6.0	inches dia.
Stack Area (As)	0.196	square feet

CALCULATED RESULTS

Water Vapor in Stack (Bws):	2.75	percent by volume
Stack Gas Molecular Wt, Dry (Md):	28.95	lb/lbmole
Stack Gas Molecular Wt, Wet	28.65	lb/lbmole
Stack Gas Velocity (Vs):	77.68	feet/second
Stack Gas Flow Rate (Qs):	495	DSCFM(68 deg.F)

MONITORING & LABORATORY DIVISION
ENGINEERING & CERTIFICATION BRANCH

FIELD DATA SHEET

FILE NO.:	T-01-040	PITOT TUBE FACTOR (Cp)	0.84
PROJECT NAME:	SMUD/Capstone 30	PROBE TIP DIA, in. (Dn)	N/A
RUN NO.:	50% Load	STACK DIA, inches	6.0
LOCATION	Turbine Stack	STATIC PRESS, "H2O (Ps)	-0.20
BAR. PRESS, "Hg(Pb)	29.91	METER TEMP, F	60

SAMPLE POINT	t CLOCK TIME min.	Vm DRY GAS METER cu. ft.	dP PITOT PRESS. in. H2O	dH ORIFICE PRESS. (ACTUAL) in. H2O	Ts STACK TEMP. F
START	0	0	—	—	—
1E			0.63		447
2E			0.70		444
3E			0.76		443
4E			0.76		443
1W			0.62		443
2W			0.74		443
3W			0.76		448
4W			0.76		447
	t= 0	Vm= 0.00	/dP avg.= 0.846	dH avg.= ERR	Ts avg.= 444.8

TEST SUMMARY AND RESULTS (FOR FIELD DATA RECORD)

FILE NO.: T-01-040
PROJECT NAME: SMUD/Capstone 30
RUN NO.: 50% Load

SUMMARY OF TEST DATA

Barometric Pressure (Pb):	29.91	inches Hg
O2 in Stack (%O2):	19.0	percent
CO in Stack (%CO):	0.00	percent
CO2 in Stack (%CO2):	1.1	percent
N2 in Stack (%N2):	79.90	percent
Pitot Tube Factor (Cp)	0.84	
Avg. of Sqrt. of Pitot Press. (/dP avg):	0.85	/(inches H2O)
Stack Temperature (Ts)	905	deg. R
Static Pressure	-0.20	inches H2O
Absolute Stack Pressure (Ps)	29.90	inches Hg
Stack Dimensions	6.0	inches dia.
Stack Area (As)	0.196	square feet

CALCULATED RESULTS

Water Vapor in Stack (Bws):	2.75	percent by volume
Stack Gas Molecular Wt, Dry (Md):	28.94	lb/lbmole
Stack Gas Molecular Wt, Wet	28.64	lb/lbmole
Stack Gas Velocity (Vs):	62.43	feet/second
Stack Gas Flow Rate (Qs):	417	DSCFM(68 deg.F)

APPENDIX B

Field Data Sheets

FIELD DATA RECORD

PAGE 1 of 2

RUN NO.	1 & 2 of 3	PROJECT NO.	
LOCATION	Stack	PLANT NAME	Sam D / Capstone
DATE	6/10/01	AMBIENT TEMP (F)	60
OPERATOR	Otradol	METER TEMP (F)	60
METER BOX NO.	30004204	BAR. PRESS ("Hg)	29.98
LOCAL TIME	0430	STATIC PRESSURE ("H2O)	-0.69
START/STOP	0730 (water test)	ASSUMED MOISTURE (%)	
STACK DIAMETER	6"	ASSUMED O2 (%)	FB
Ym:	1.011	ASSUMED CO2 (%)	
H@:	1.561	ASSUMED MW (WET, %)	
		ASSUMED MW (DRY, %)	

PITOT TUBE FACTOR 0.84
NOZZLE DIAMETER N/A in.
PROBE LENGTH 3'4" ft.

SAMPLE TRAIN LEAK TEST:
BEFORE 15 in. H_2O
AFTER in. H_2O
PITOT TUBE LEAK TEST
BEFORE 4½" ok AFTER

	POINT	CLOCK TIME	DRY GAS METER (cu. ft.)	VELOCITY dP (in. H2O)	ORIFICE dH (in. H2O) DESIRED (Pre ✓)	ORIFICE dH ACTUAL (vel. check @100%)	TEMPERATURES (F) STACK #1	PROBE	FILTER #2	RESIN	IMPGR #3	PUMP VAC (in. Hg)
					E (1)	2	528		Amb			
100% ~28.0kw	START	0	407.22	1.6	1.4 1.3 523	100% = 28.0 kw					—	—
		5	411.23	2.0	1.4 1.4		528		58		44	6
		15	419.27	1.9	1.6 1.7		529		59		44	6
		25	427.21	1.9	1.6 1.7		529		59		45	6
75%=21.0 kw	~30											
		35	435.16	1.1		2.0	493		59		45	6
		45	443.25	1.1		2.0	486		59		45	6
		55	451.27	1.1		2.0	486		59		45	6
50%=14.0 kw	~60								~~60~~			
		65	459.29	0.76		2.0	447		60		45	6
		75	467.30	0.76		2.0	444		57		45	6
		85	475.35	0.76		2.0	443		58		45	6
50%=14.0 kw	90											
		95	483.42	0.76		2.0	443		58		45	6
		105	491.53	0.76		2.0	443		59		45	6
		115	499.64	0.76		2.0	443		58		45	6
75%=21.0	120											
		125	507.63	1.1		2.0	484		58		46	6
		135	516.	1.1		2.0	486		58		46	6
		145	523.71	1.1		2.0	486		58		46	6
28.0kw 100%	150											
		155	531.75	1.6		2.0	527		58		46	6
		165	540	1.6		2.0	527		62 ~~58~~		46	6
~28.0kw 100%	End H2O Temp	175	547.79	1.6		2.0	528		60		46	6
	180											
		Theta:	Vm:	avg dP:		avg dH:	avg Ts					

FIELD DATA RECORD

PAGE 2 of 3

RUN NO. 3	PITOT TUBE FACTOR 0.84	PROJECT NO. 01-040
LOCATION stack	NOZZLE DIAMETER N/A in.	PLANT NAME Small/Capstone
DATE 6/10/01	PROBE LENGTH 3 1/4 ft.	AMBIENT TEMP (F) 60
OPERATOR Dodd		METER TEMP (F) 60
METER BOX NO.. 20004204		BAR. PRESS ("Hg) 29.94
LOCAL TIME 0430		STATIC PRESSURE ("H2O) - 0.69
START/STOP 0905 - Fan down Test	SAMPLE TRAIN LEAK TEST:	ASSUMED MOISTURE (%)
	BEFORE 15 in. H_2O	ASSUMED O2 (%) 18
STACK DIAMETER 6.0"	AFTER 15 in. H_2O	ASSUMED CO2 (%)
Ym: 1.011	PITOT TUBE LEAK TEST	ASSUMED MW (WET, %)
H@: 1.561	BEFORE 4 1/2" ok AFTER 4" ok	ASSUMED MW (DRY, %)

	POINT	CLOCK TIME	DRY GAS METER (cu. ft.)	VELOCITY dP (in. H2O)	ORIFICE dH (in. H2O) DESIRED	ORIFICE dH (in. H2O) ACTUAL	TEMPERATURES (F) STACK	PROBE	~~FILTER~~ Amb	RESIN	IMPGR	PUMP VAC (in. Hg)
kW	~~START~~	~~0~~	—	—	—	—	—	—	—	—	—	—
100%=28.0	180				E W							
		185		1.6			530		60			
		195		1.6			528		61			
		205		1.6	75% Vel Trav	75%	528		61			
75%=21.0	210			→	~~1.0~~ 0.93 0.93	Static = -0.13" H2O						
		215		1.1	1.1 1.0		498		60			
		225		~~1.6~~ 1.1	1.1 1.1		489		63			
KW 50%=14.0		235		1.1	1.1 1.1		490		62			
	246				25% Vel. Trav.							
		245		0.76	0.63 0.62		448		63			
		255		0.76	~~0.69~~ 0.70 0.74	Static = 0.20"	~~471~~ 447		62			
		265		0.76	~~0.79~~ 0.76		448		65			
	270	start 55% and @ 280			~~0.74~~ 0.76		~~447~~					
15.4kW	55%	280		0.82			455		64			
16.8 kW	60%	290		0.90			468		~~72~~ 68			
18.2 kW	65%	300		0.98			479		68			
19.6 kW	70%	310 (switch to 75% @ 310)		1.0			488		66			
21.0 kW	75%	325		1.1			502		68			
22.4kW	80%	335		1.3			508		66			
23.8kW	85%	345		1.4			517		67			
25.2kW	90%	355		1.5			527		70			
26.6kW	95%	~~365~~ 367		1.55			527		71			
26.6 actual 28.0kW	100%	375 Wanted 28.0 Got 27.0		1.6			529		71			
7.0 kW	25%	~~385~~ System Fault & restart		~~0.40~~ ← 0.40			408		72			
		Theta 395	Vm:	avg dP:		avg dH:	avg Ts					

Califor Ir Resources Bd.
Monitoring Laboratory Division

Project Log & Special Data

Oscar @ 7:41:24
me — 7:39:42

Project: SMUD Capston	Page #: 1 of 2
Project #:	Date: 6/10/01
Project Leader: D Todd	

	Time	Barometric Pressure, in. hg.	Temperatures Ambient F	Inlet (dry) F	Inlet (wet) F		Power Output Capstone kWatts	SMUD kWatts		Fuel Flow PG&E cu. ft.	SMUD cu. ft.
Prestart 1	2:33:38	29.90	58	61	54		28.0			1395885.0	
Start 2	4:36:15						27.7-28.1			1396145.0	
100% 3	4:47:00	29.91	58	58	54		~~28.0~~			1396195.0	
100 4	4:53:23		59				27.7-28.1			6240.0	
5	5:01:47	Time adjust					27.7-28.1			6275.0	
75% 6	5:12:01	29.91	58	58	53		20.7-21.0			6310.0	
75 7	5:23:03						20.7-21.1			6343.0	
8	5:33:08	29.91	58	58	53		20.8-21.1			6376.0	
50% 9	5:43:59						13.8-14.1			6406.0	
10	5:53:02	29.91	58	57	52		13.8-14.0			6427.0	
11	6:03:05						13.9-14.0			6450.0	
12	6:13:18	29.91	58	57	53		13.9-14.0			6474.0	
50 13	6:23:01						13.9-14.0			6497.0	
14	6:33:00	29.91	58	56	53		13.9-14.0			6520.0	
15	6:42:55						20.8-21.0			6548.0	
75 16	6:53:01	29.92	59	58	53		20.8-21.0			6580.0	
17	7:03:00						20.8-21.0			6613.0	
100 18	7:13:00	29.92	60	58	54		27.9-28.0			6651.0	
19	7:23:00						27.8-28.0			6694.0	
20	7:33:01	29.92	61	59	54		27.8-28.0			[illegible]	
21	7:43:00						27.8-28.0			6779.0	
100 22	7:53:03	29.92	61	60	54		27.8-28.1			6822.0	

Califor Ir Resources Bd.
Monitoring Laboratory Division

Project Log & Special Data

Project: SMUD CAPSTONE		Page #: 2 of 2	
Project #:		Date: 6/10/01	
Project Leader: D. TODD & O. LOPEZ			

	Time	Barometric Pressure, In. hg.	Temperatures: Ambient F	Temperatures: Inlet (dry) F	Temperatures: Inlet (wet) F		Power Output: Capstone kWatts	Power Output: SMUD kWatts		Fuel Flow: PG&E cu. ft.	Fuel Flow: SMUD cu. ft.
100 1	8:03:00						27.8-28.0		1.39	6864.0	
2	8:13:00	29.925	65	61	55		20.8-21.1		"	6902.0	
3	8:23:00						20.8-21.1		"	6935.0	
75 4	8:33:01	29.93	67	61	55		20.8-21.0			6969.0	
5	8:43:27						20.8-21.0			7003.0	
6	8:53.00	29.93	65	63	56		13.8-14.0			7028.0	
50 7	9:03:00									7052.0	
8	: :										
9	: :										
10											
11											
12											
13											
14											
15											
16											
17											
18											
19											
20											
21											
22											

Project No. I-01-040
Date 6/10/01
Time 0430 - 0630

WATER VAPOR CALCULATIONS

Standard Conditions: 68°F and 29.92 in. Hg

Ambient Conditions 60 °F and 29.91 in. Hg

Y = 1.011

Time	Gas Volume Through Meter (Vm), Ft^3	Impinger Temp. (Ti), °F	Meter Temp. (Tm), °F	Orifice Pressure (ΔH), in. H_2O	Volume of Water Collected in Impinger (V_{1c}), ml	
0	407.22	45	60	2.0	Final 367	67
25					Initial 300	
55					Final 1202.2	20.2
85					Initial 1182.0	
115						
175	547.79				Net (V_{1c}) 87.2	

$V_m = 140.57$ 45 $T_m = 60°F$ 2.0

Assume 1 gram H_2O = 1 ml H_2O

+460 °R
520 °R

A. Gas Volume Metered ($V_{m_{std}}$)

$$P_{ma} = P_{bar} + (\Delta H/13.6) = (29.91) + \frac{(2.0)}{13.6} = \underline{30.057} \text{ in. Hg}$$

$$V_{m_{std}} = \frac{(Y) 528 \text{ °R}}{29.92 \text{ in. Hg}} \quad \frac{V_m P_{ma}}{T_m} = (Y) \; (\cancel{17.65}) \frac{(140.57)(30.057)}{(520)} = \underline{\cancel{144.986}} \text{ S DCF}$$

1.011; 17.647; 144.962

B. Volume of Water Collected ($V_{w_{std}}$)

$$V_{w_{std}} = (0.04707 \frac{ft^3}{ml}) (V_{1c}) = (0.04707) \; (87.2) = \underline{4.105} \text{ SCF}$$

C. Moisture Content in Stack Gas (Bw) in Percent

$$Bw = \frac{B}{A + B} \times 100 = \frac{(4.105)}{(144.962 + 4.105)} \times 100 = \underline{2.753 \; \% \; H_2O}$$

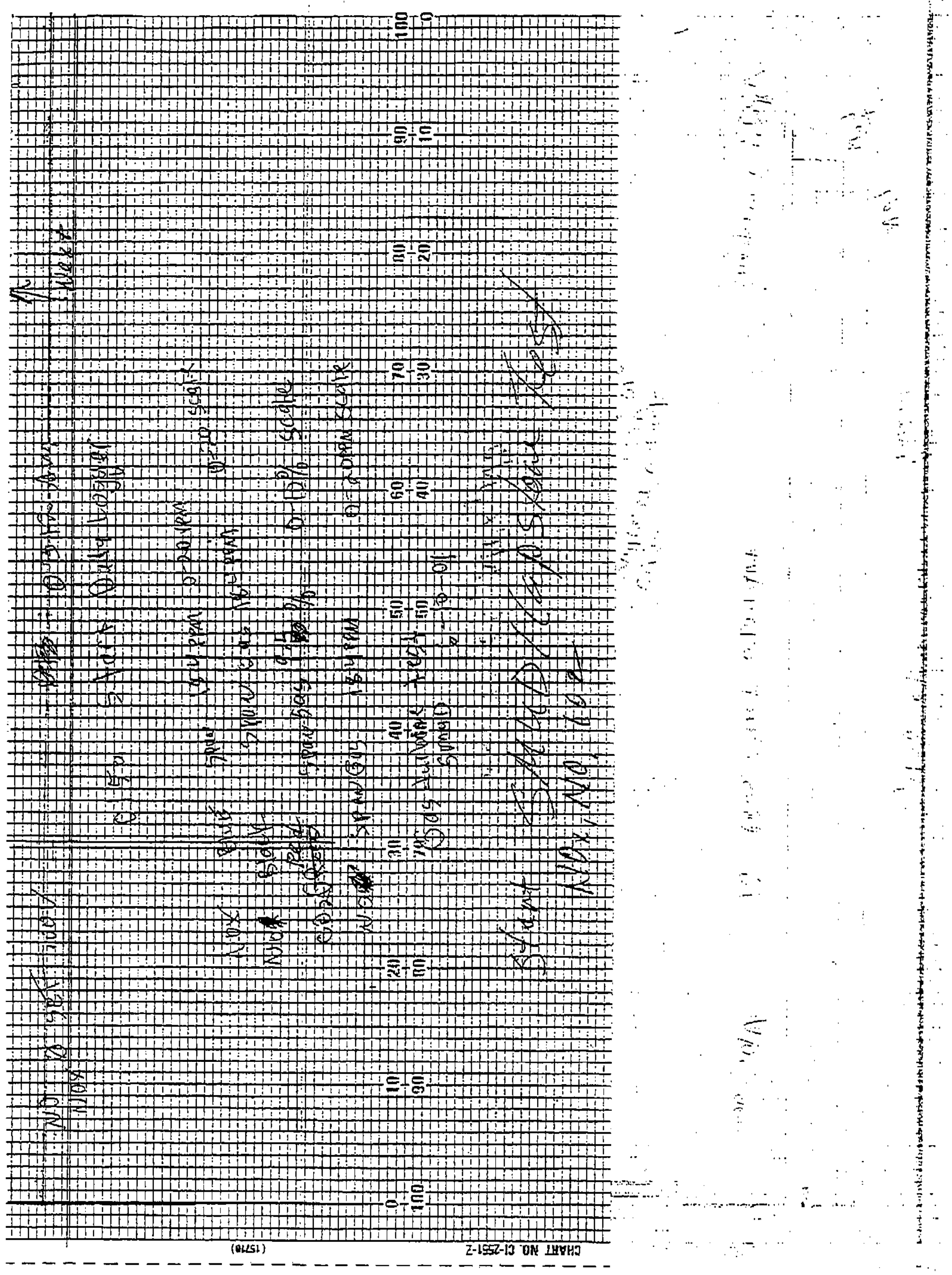
D. If calculated moisture content (ε) is greater than at saturation temperature (e.g. 212°F or below) use the table for moisture content.

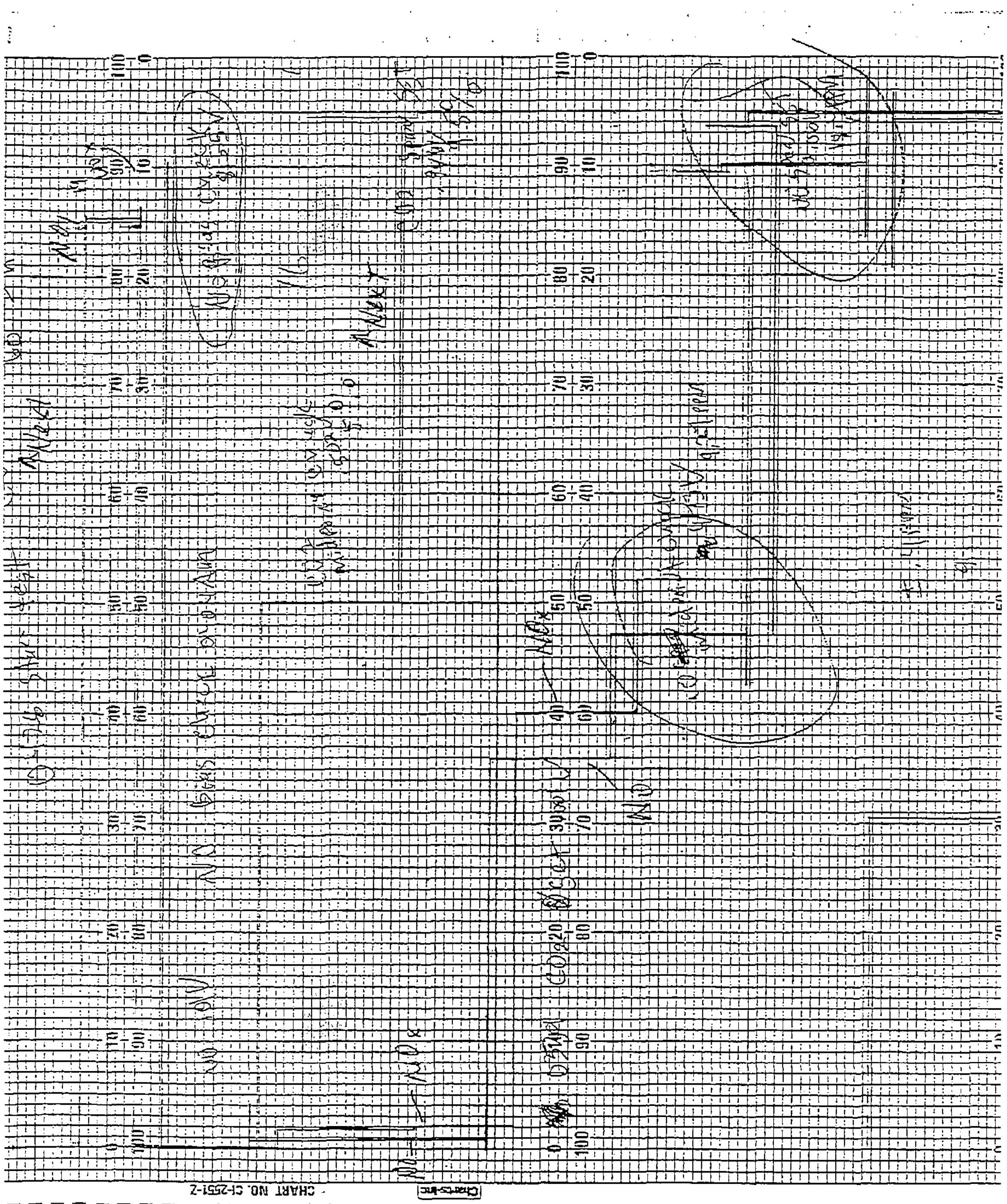
% OF H_2O AT SATURATION

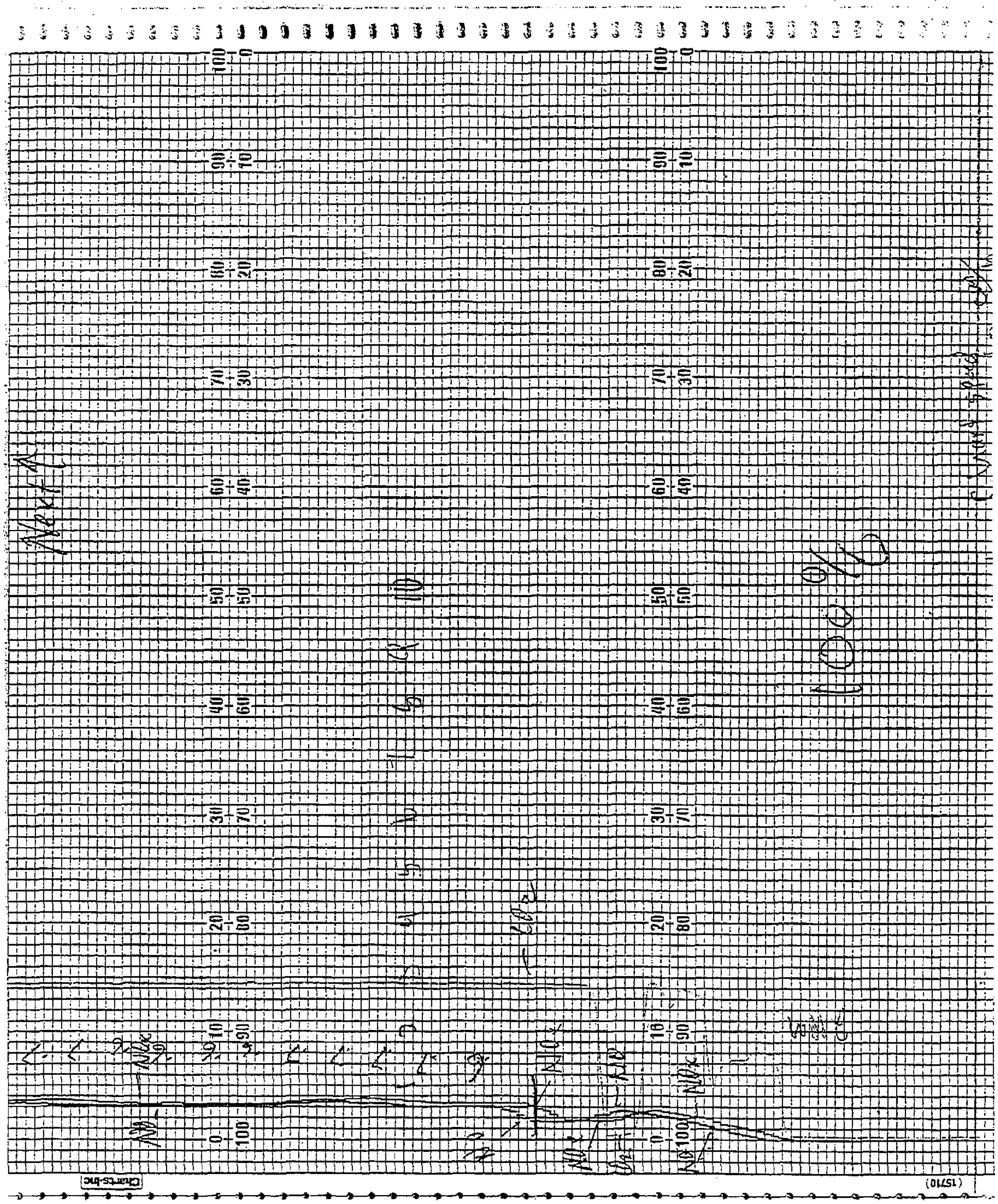
Temp. °F	% H_2O	Temp. °F	% H_2O	Temp. °F	% H_2O
50	1.2	130	15.1	180	51.1
60	1.7	140	19.7	185	57.0
70	2.5	150	25.3	190	63.6
80	3.5	155	28.7	195	70.8
90	4.8	160	32.3	200	78.6
100	6.5	165	36.4	205	87.0
110	8.7	170	40.8	210	96.2
120	11.5	175	45.7	212	100.0

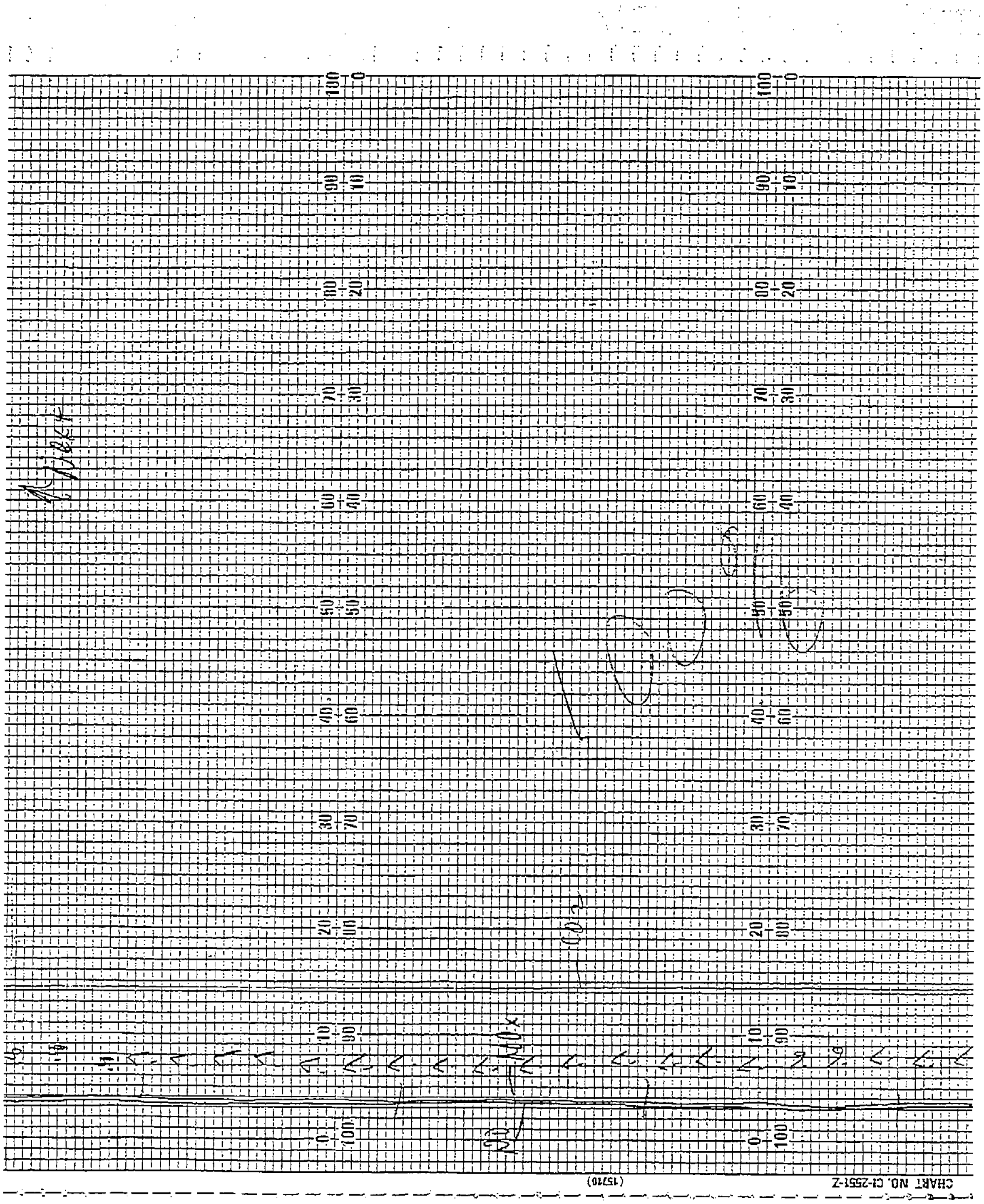
APPENDIX C1

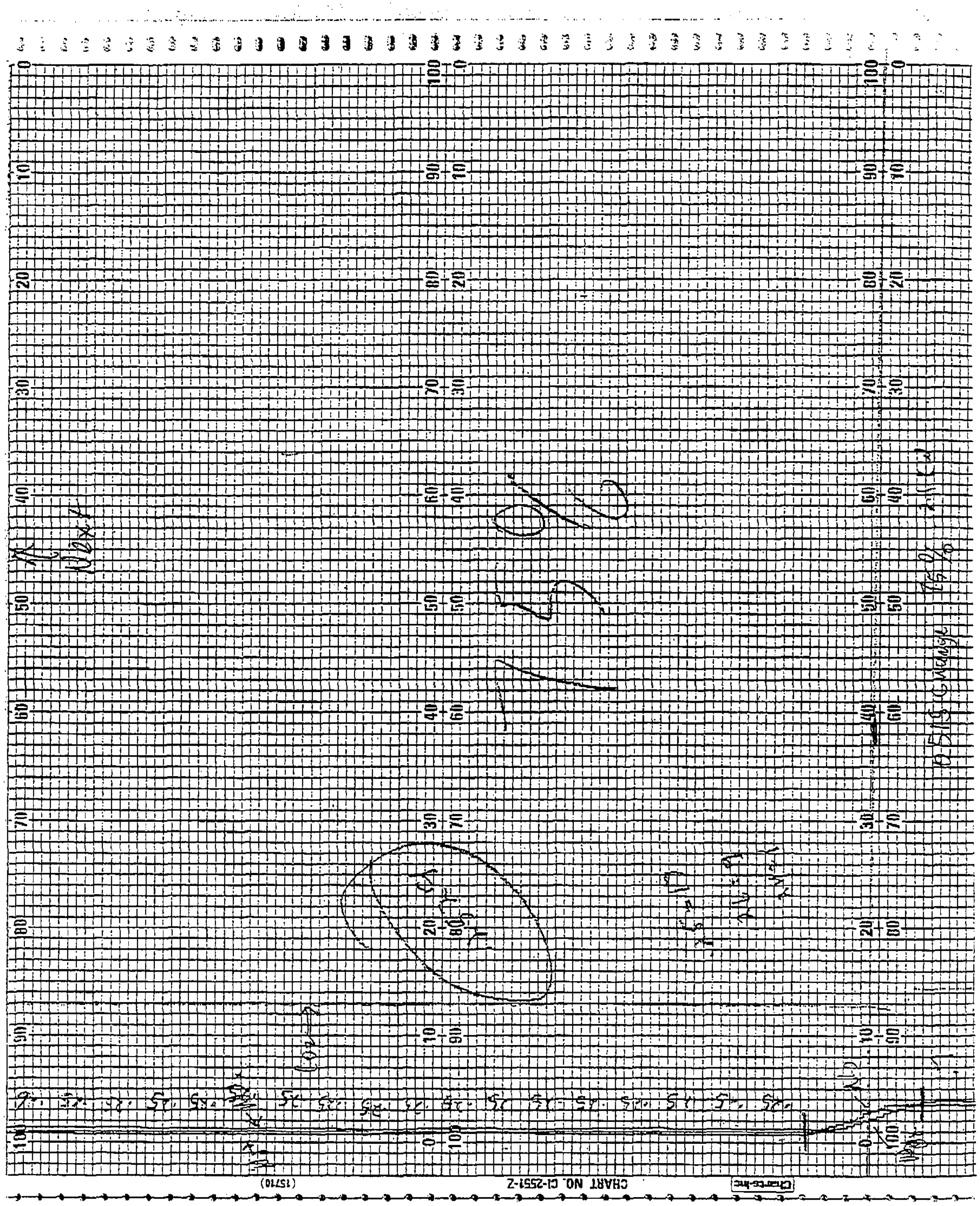
NO_x, NO, and CO_2 Gas Analyzer Strip Charts

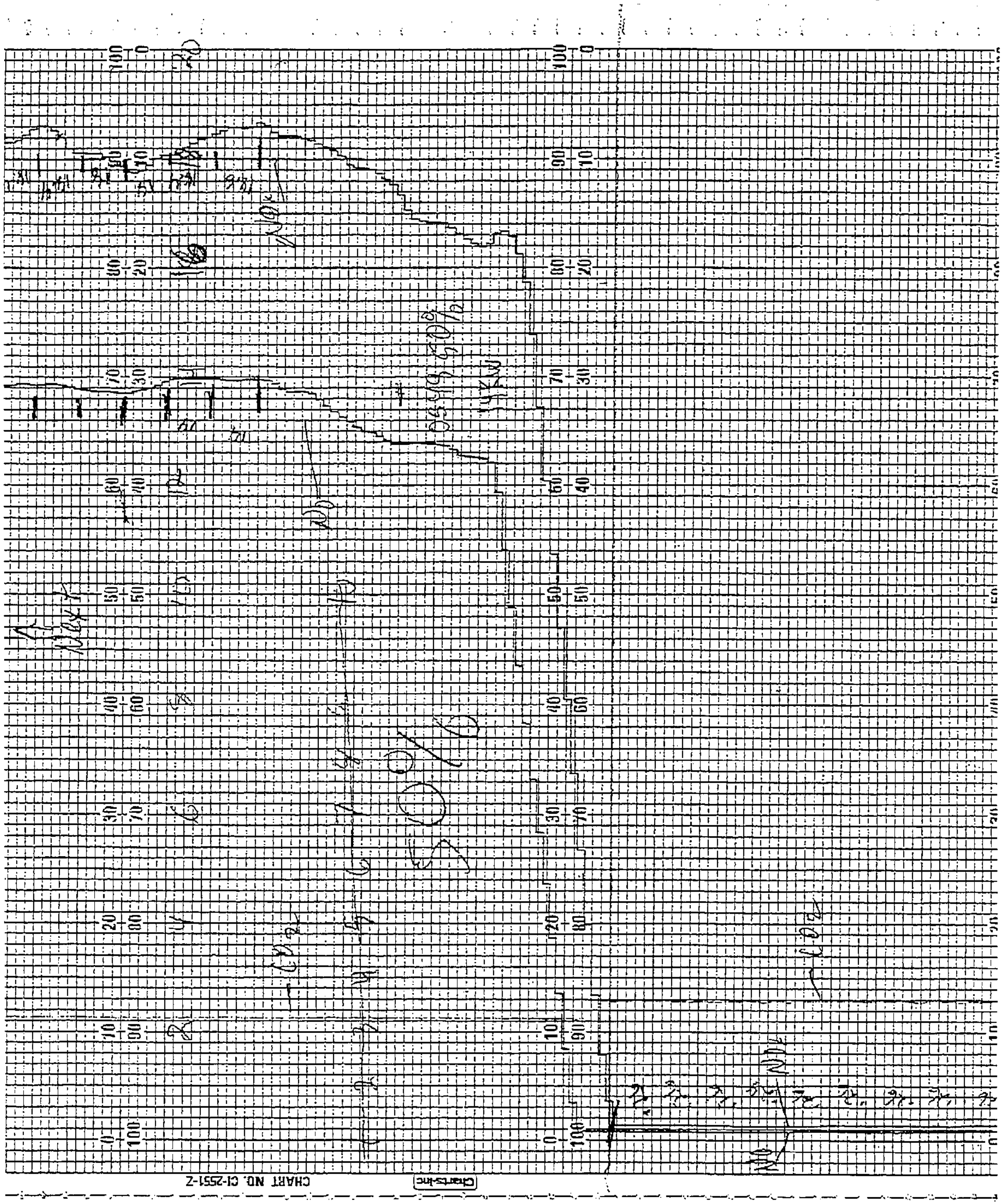


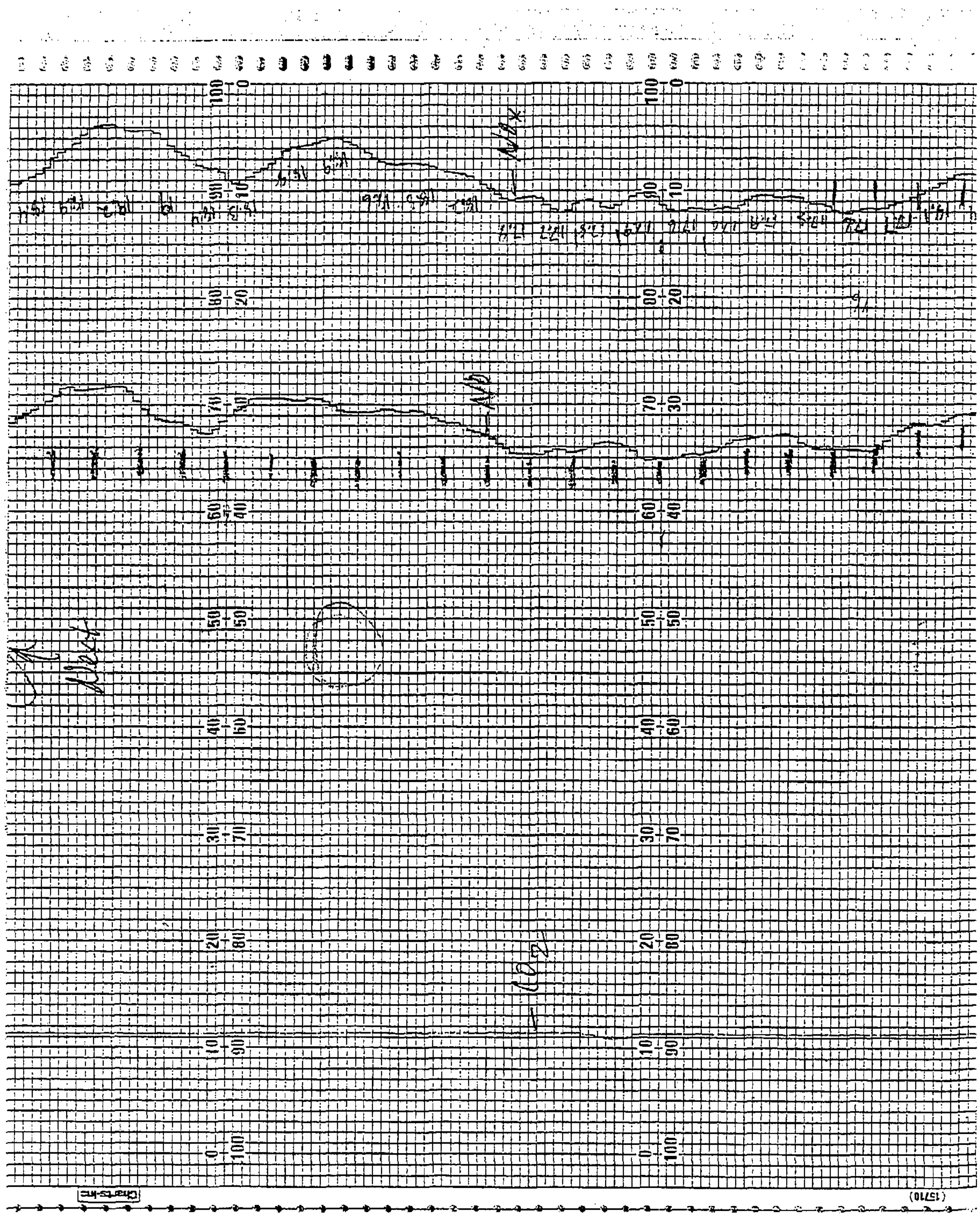


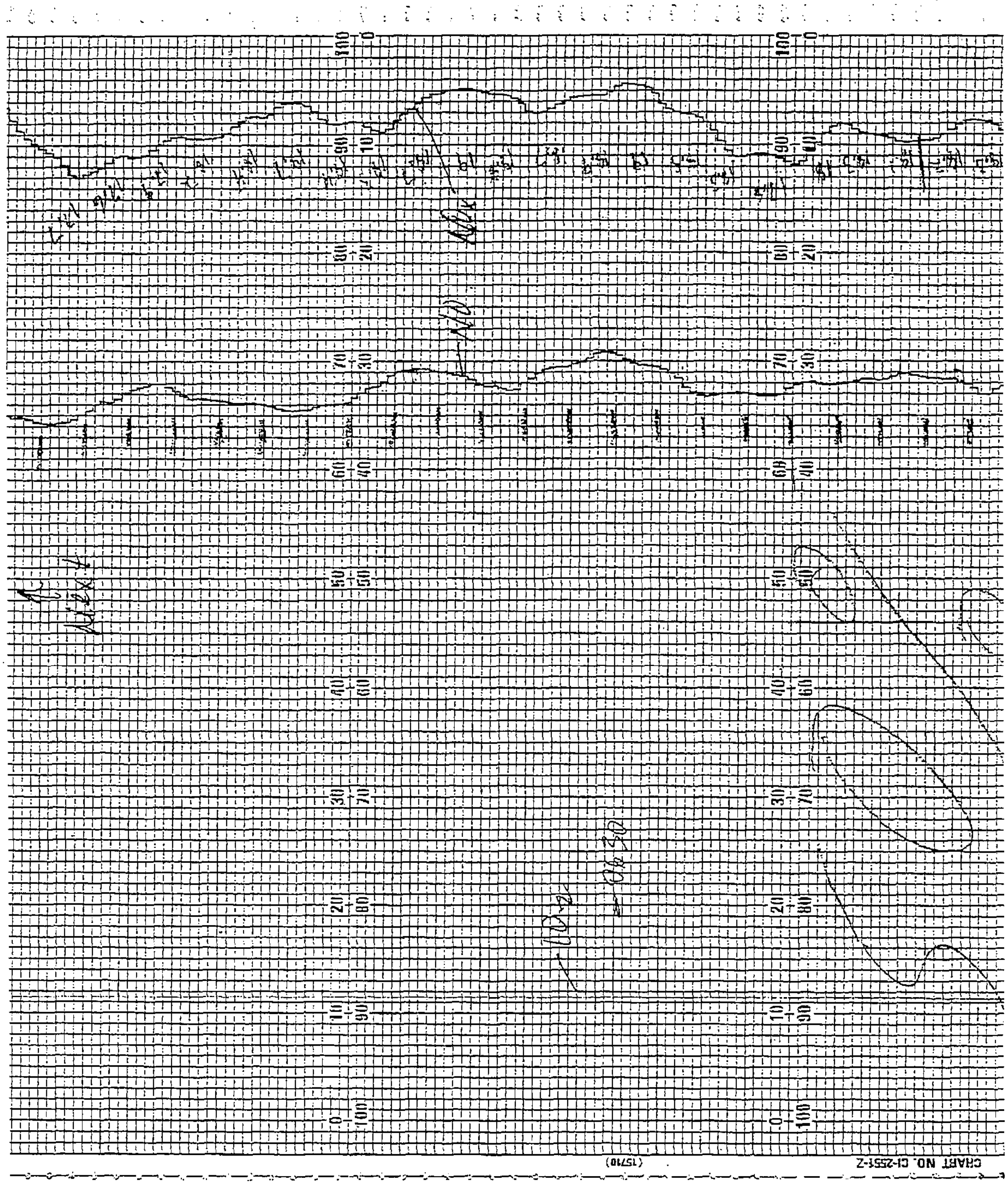


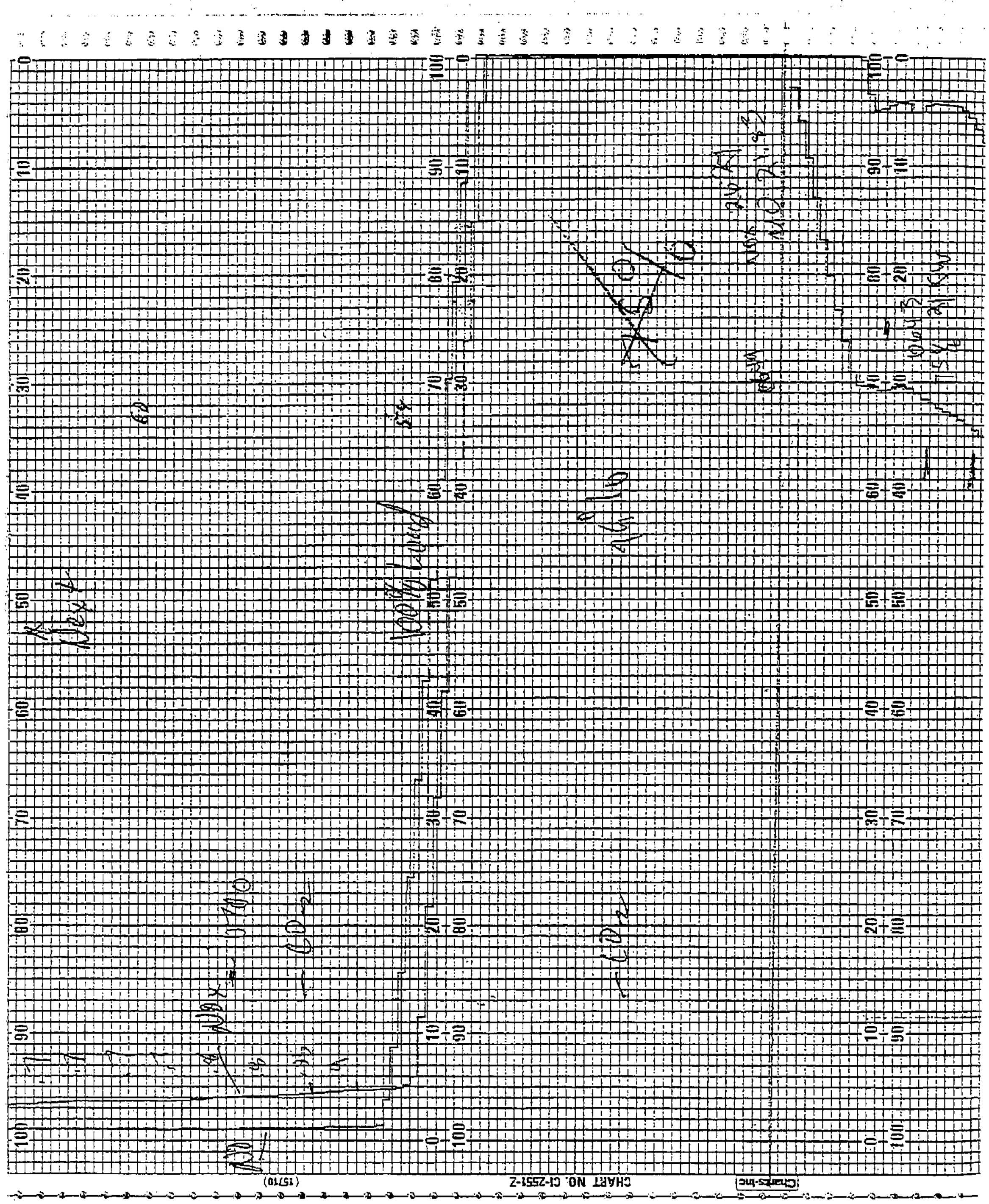


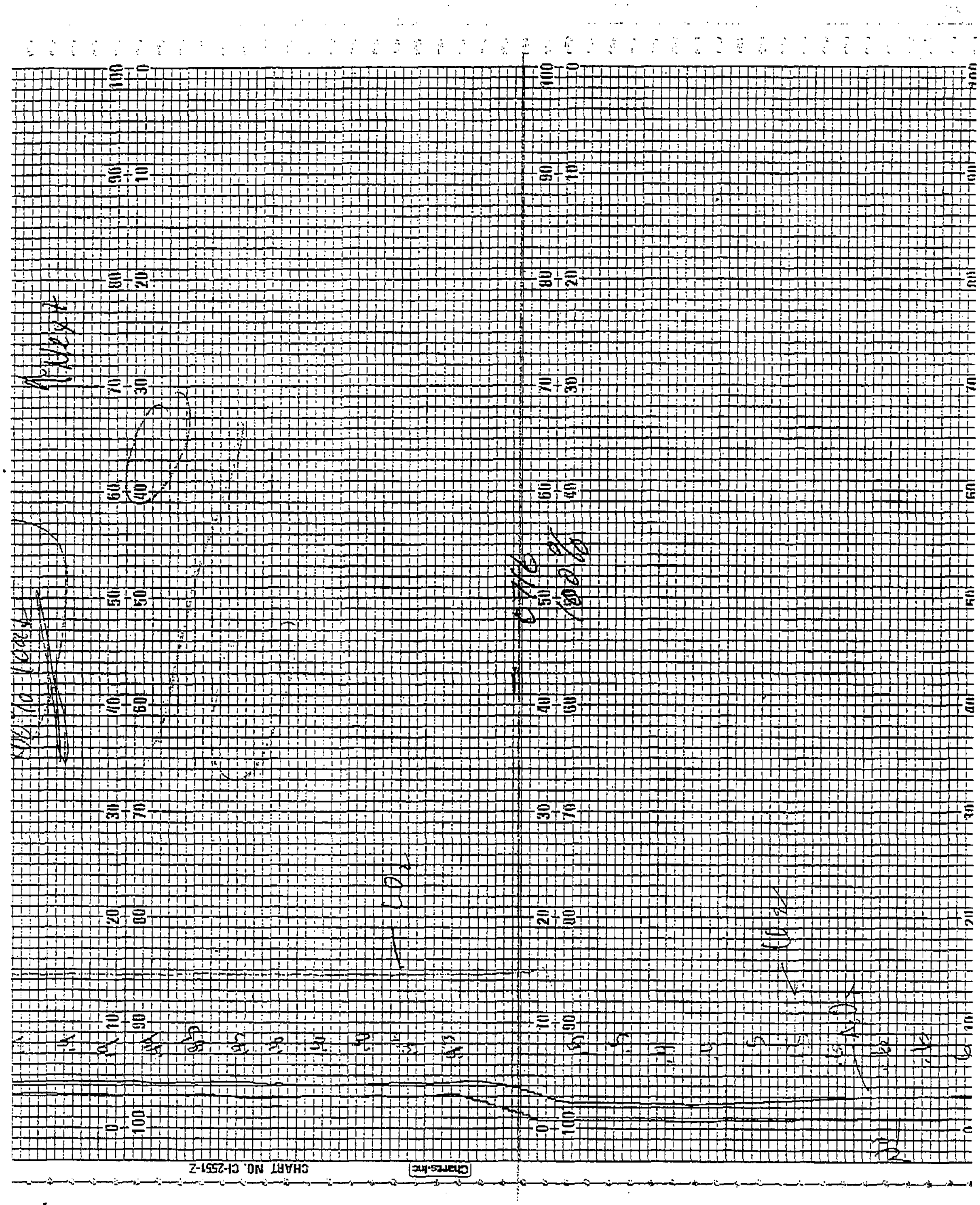


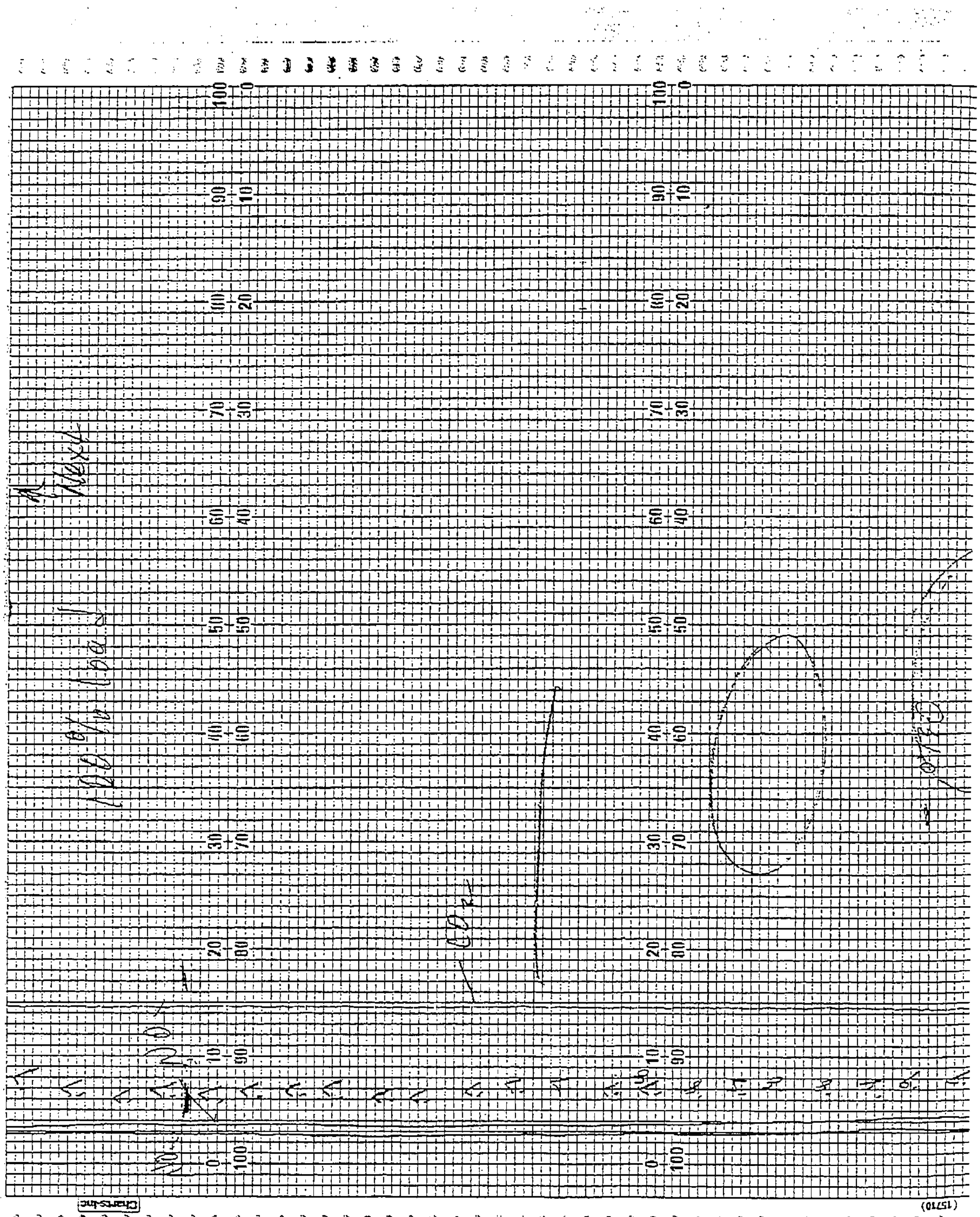












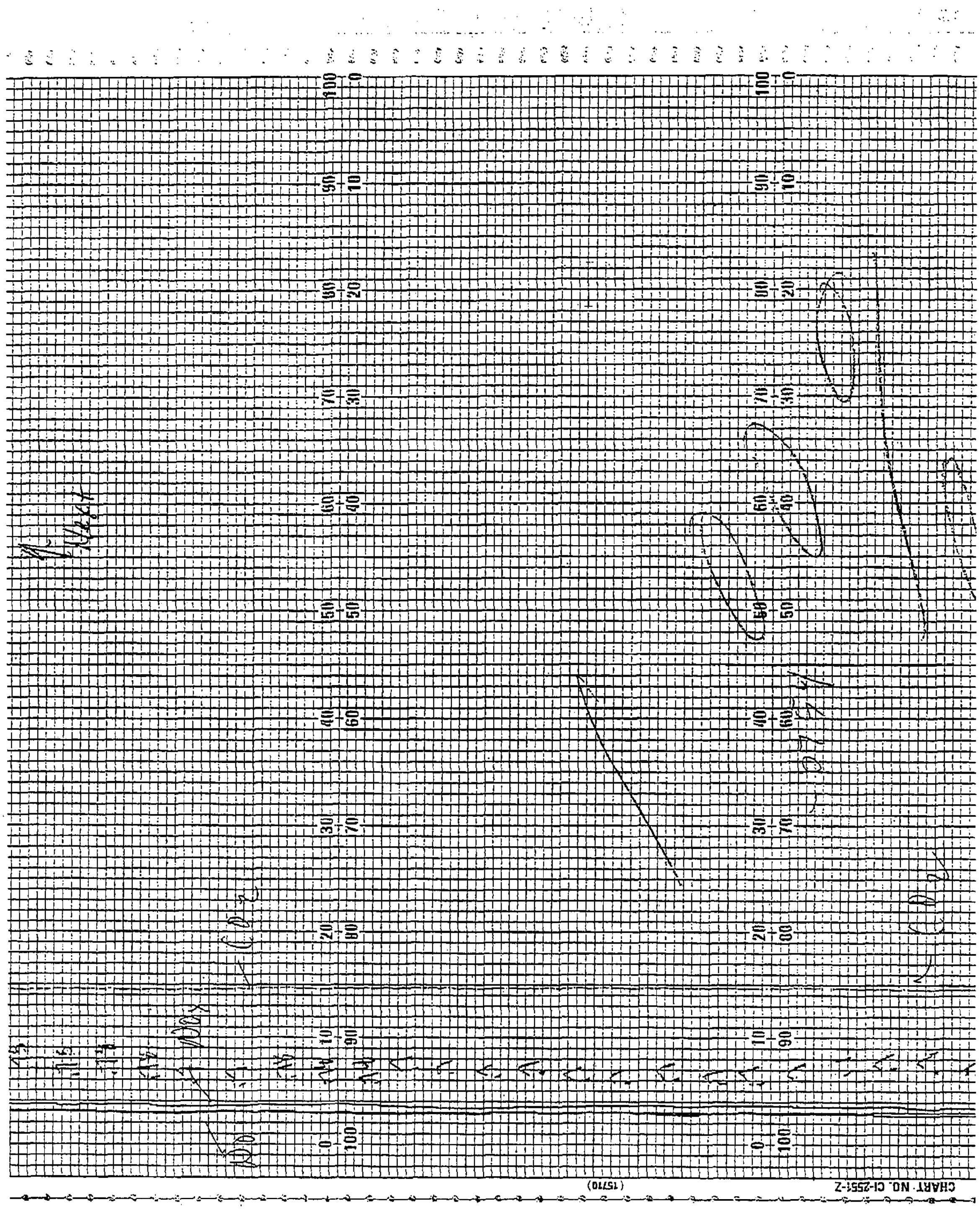
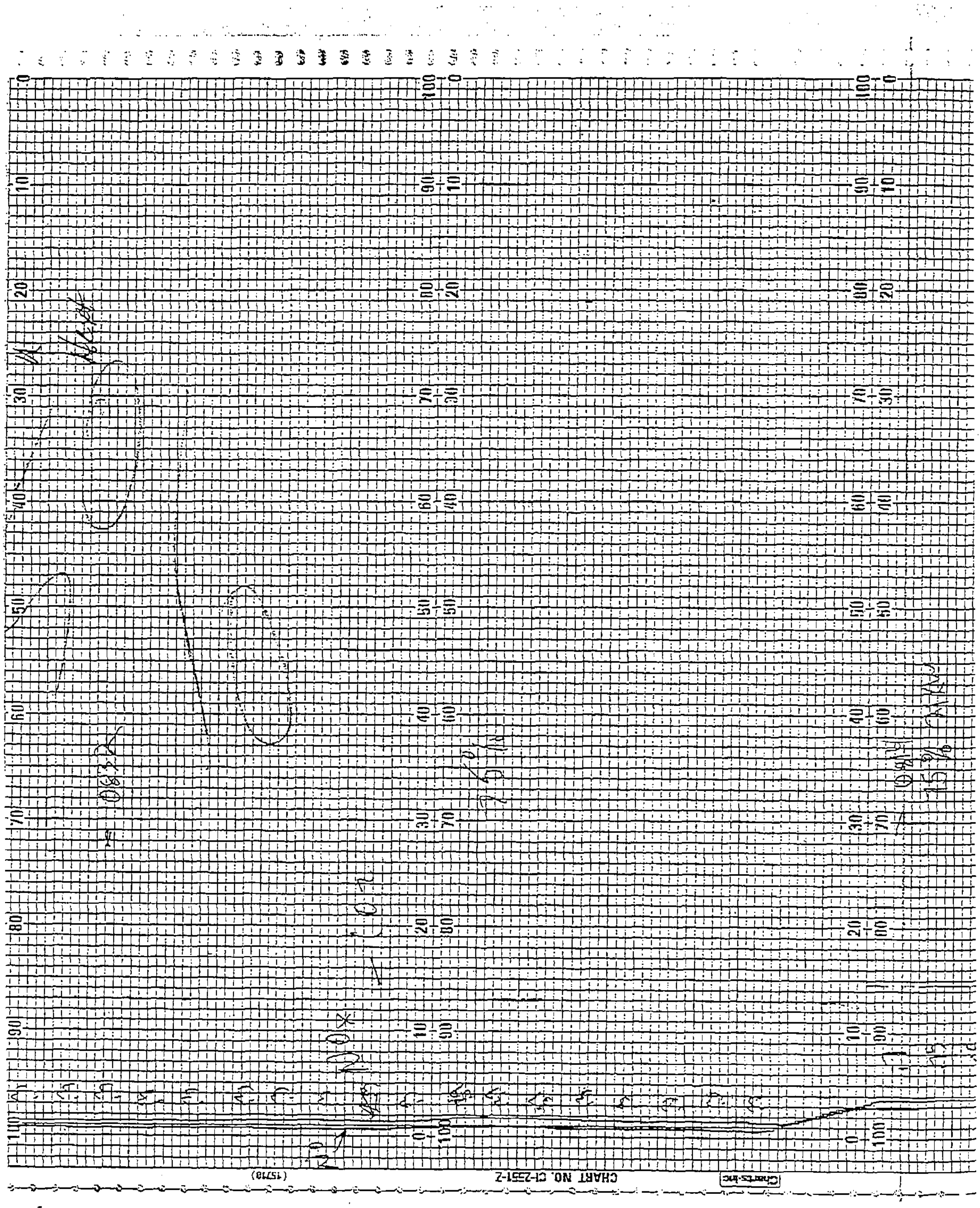
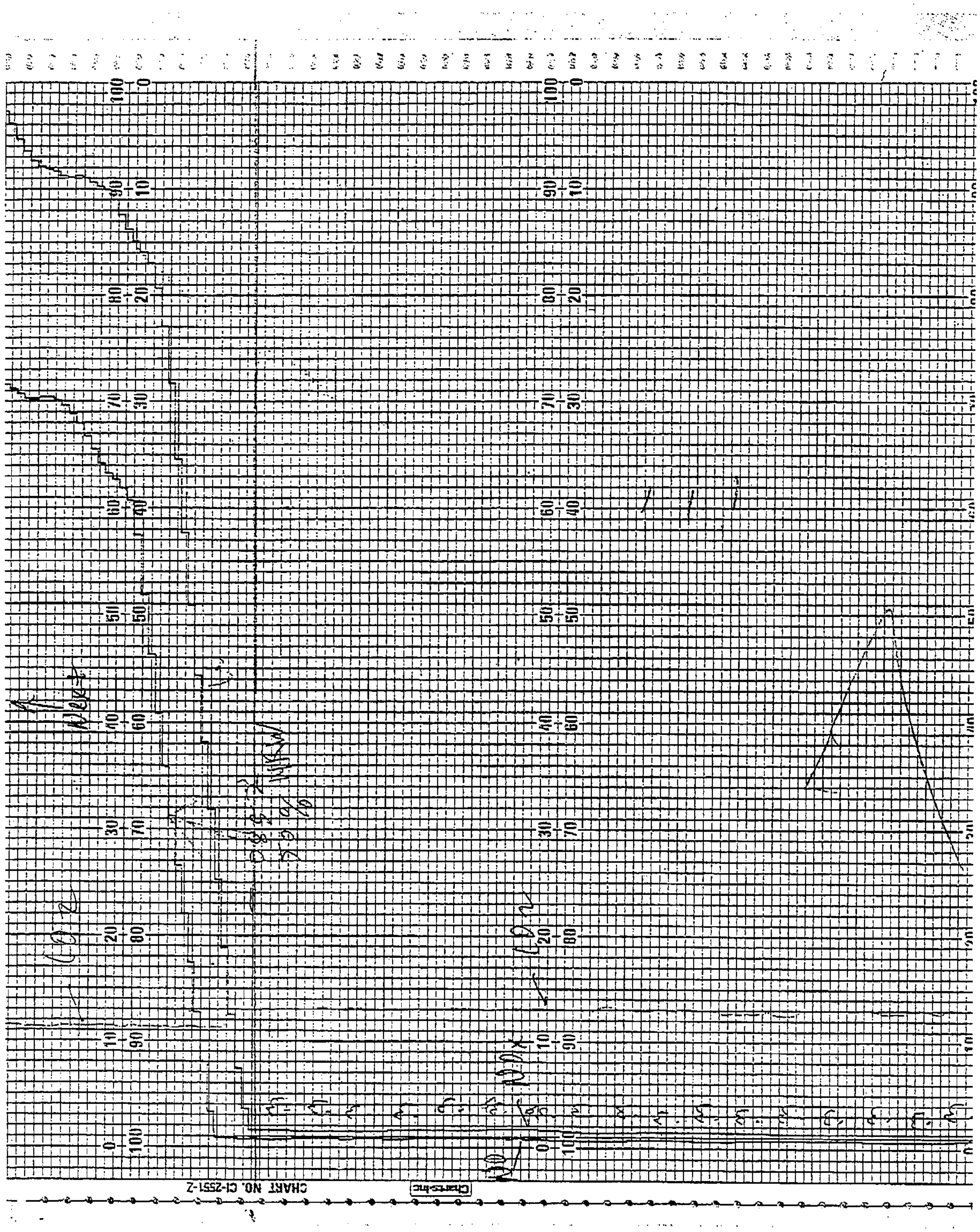


CHART NO. CI-2551-Z
(15710)





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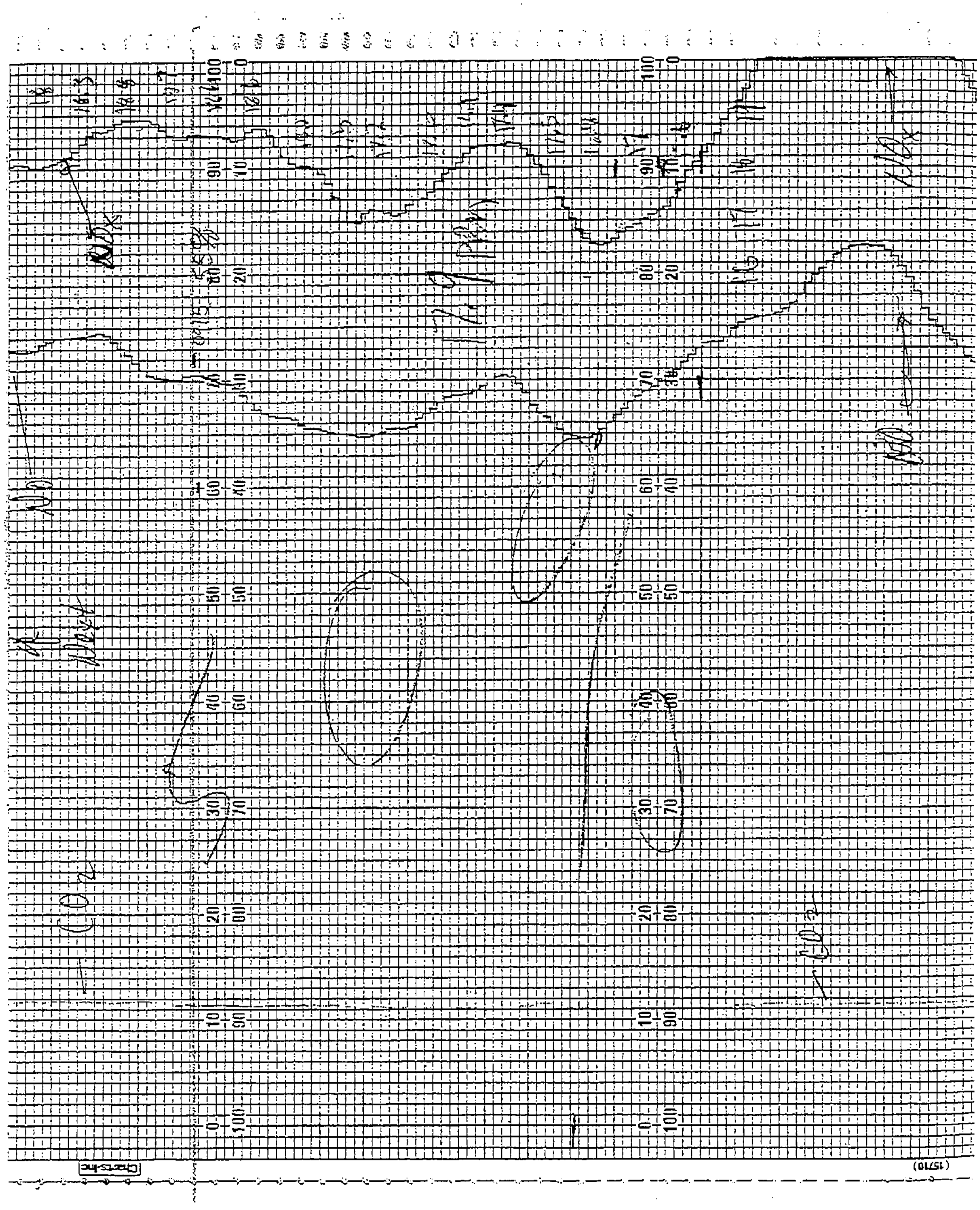
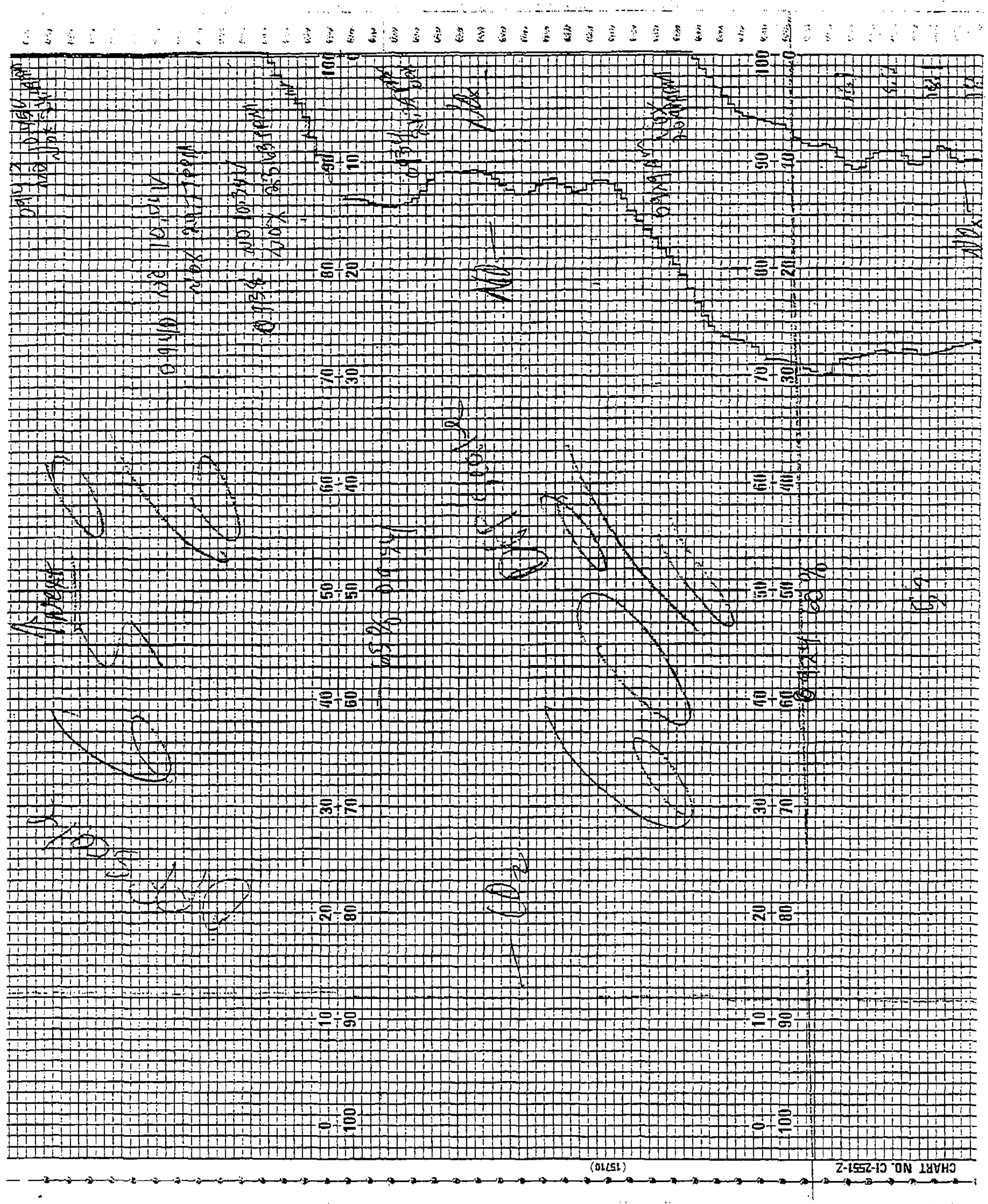
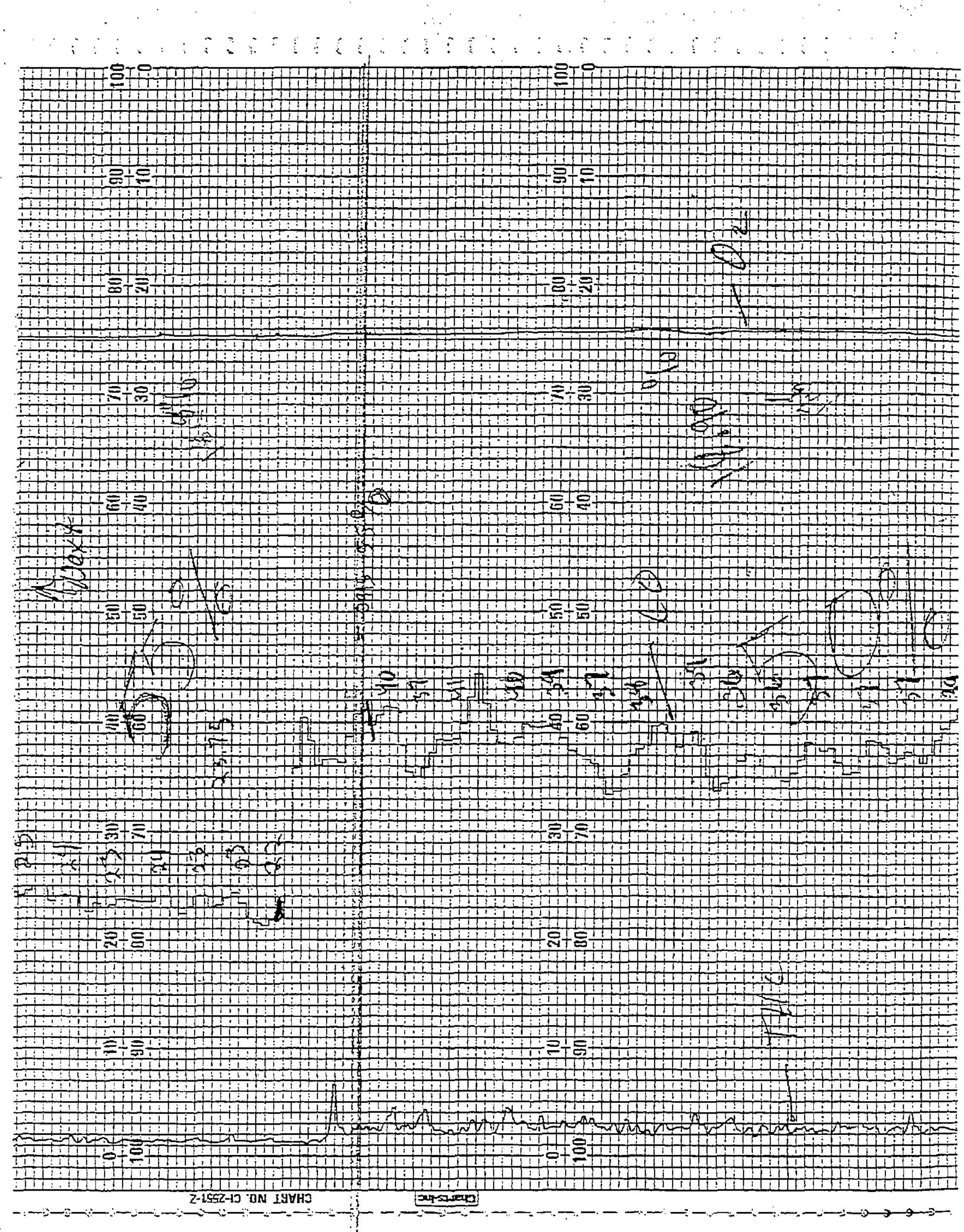
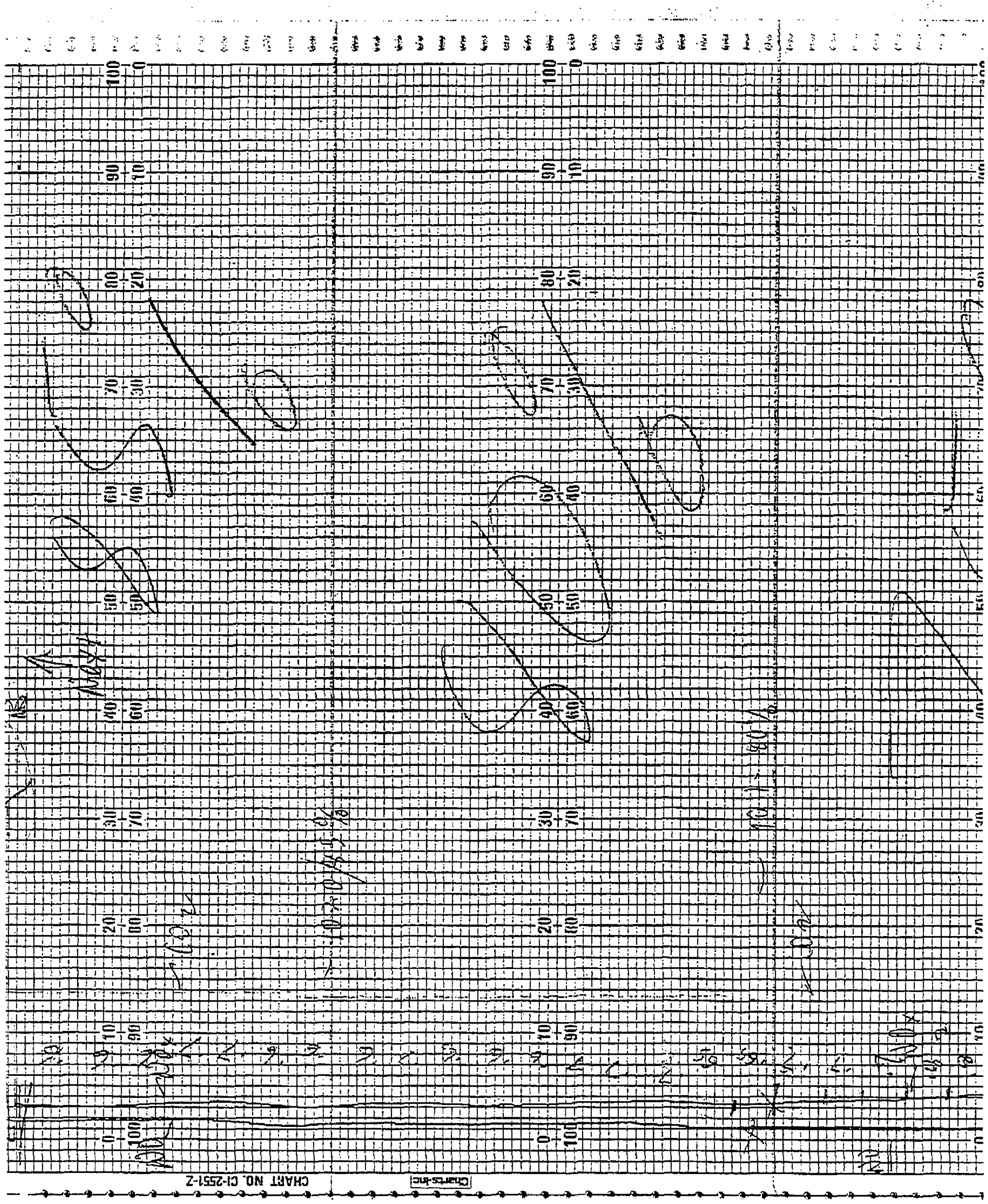
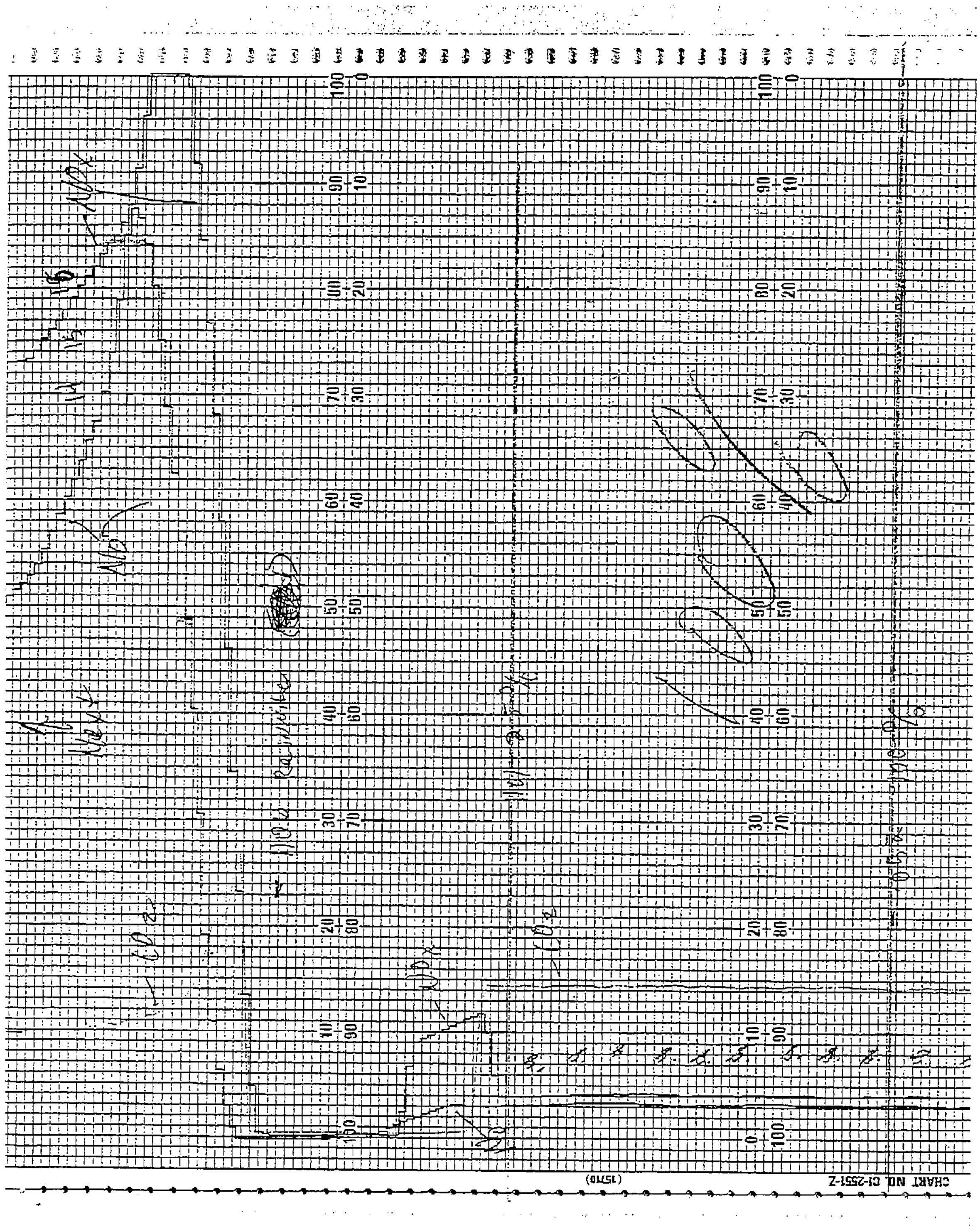
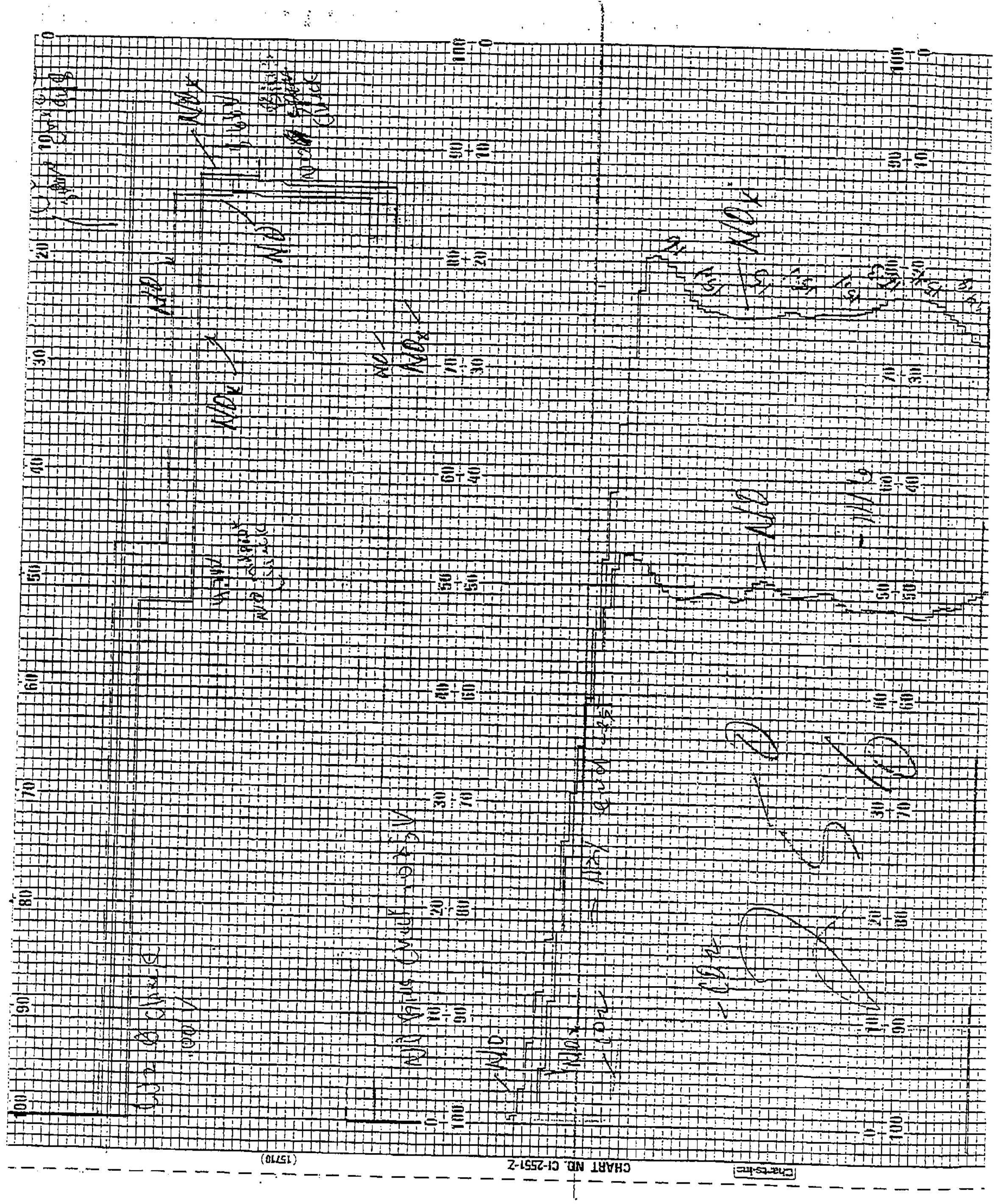


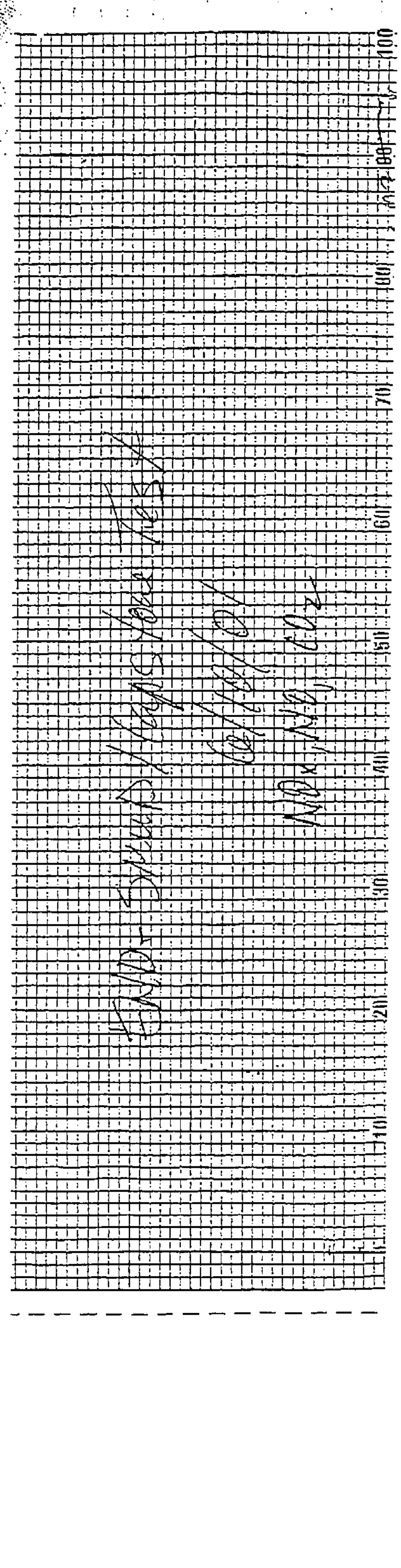






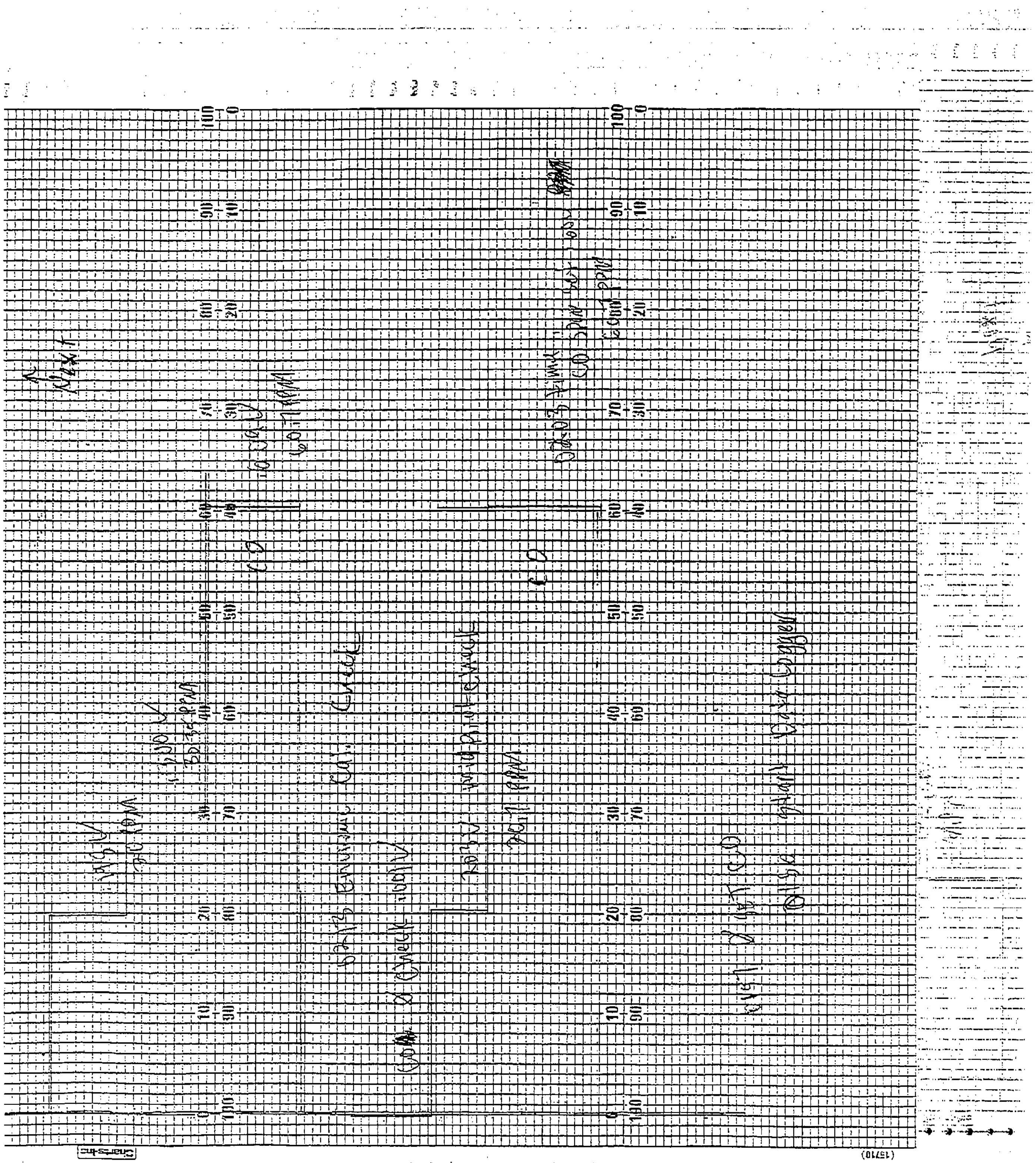


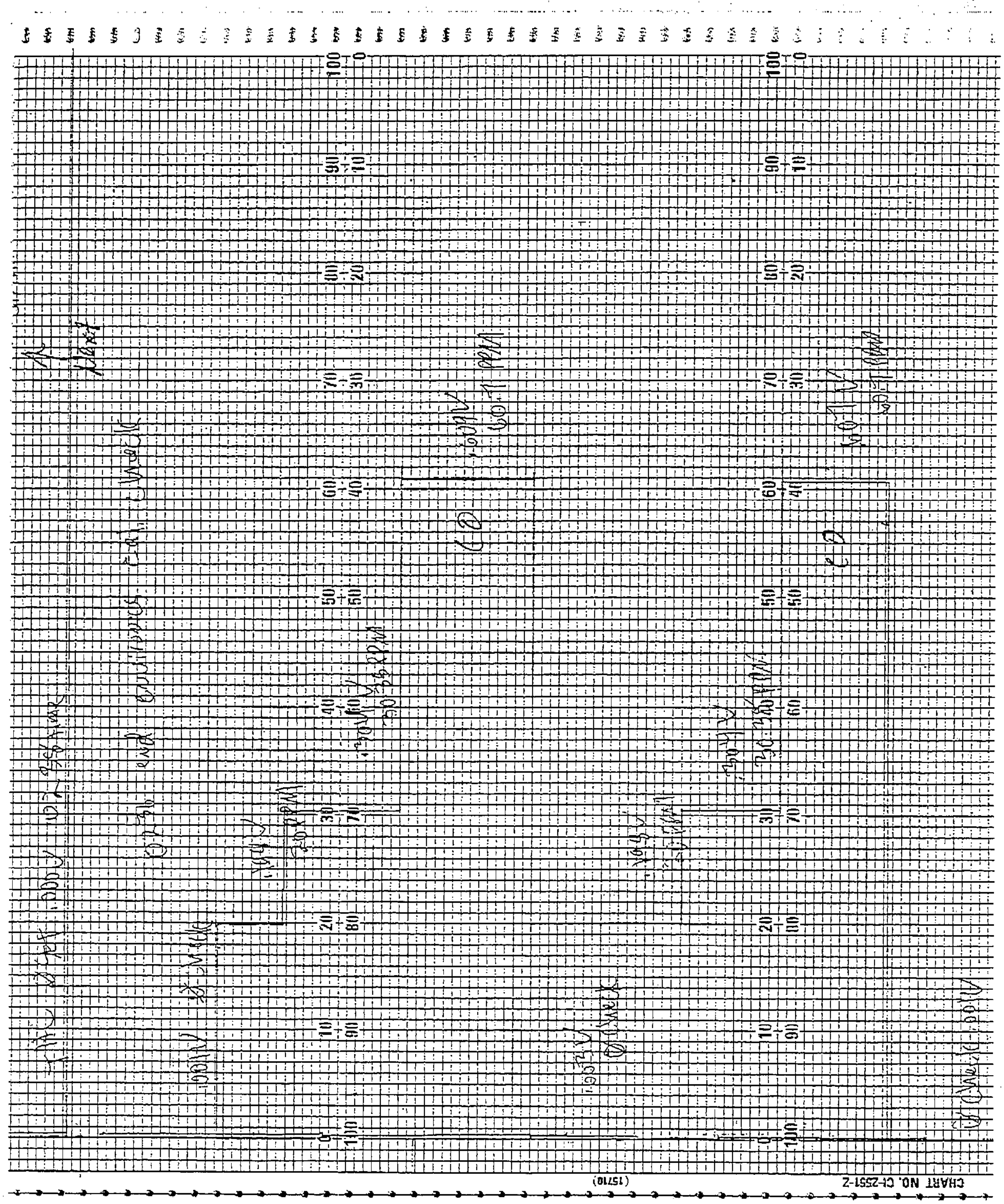


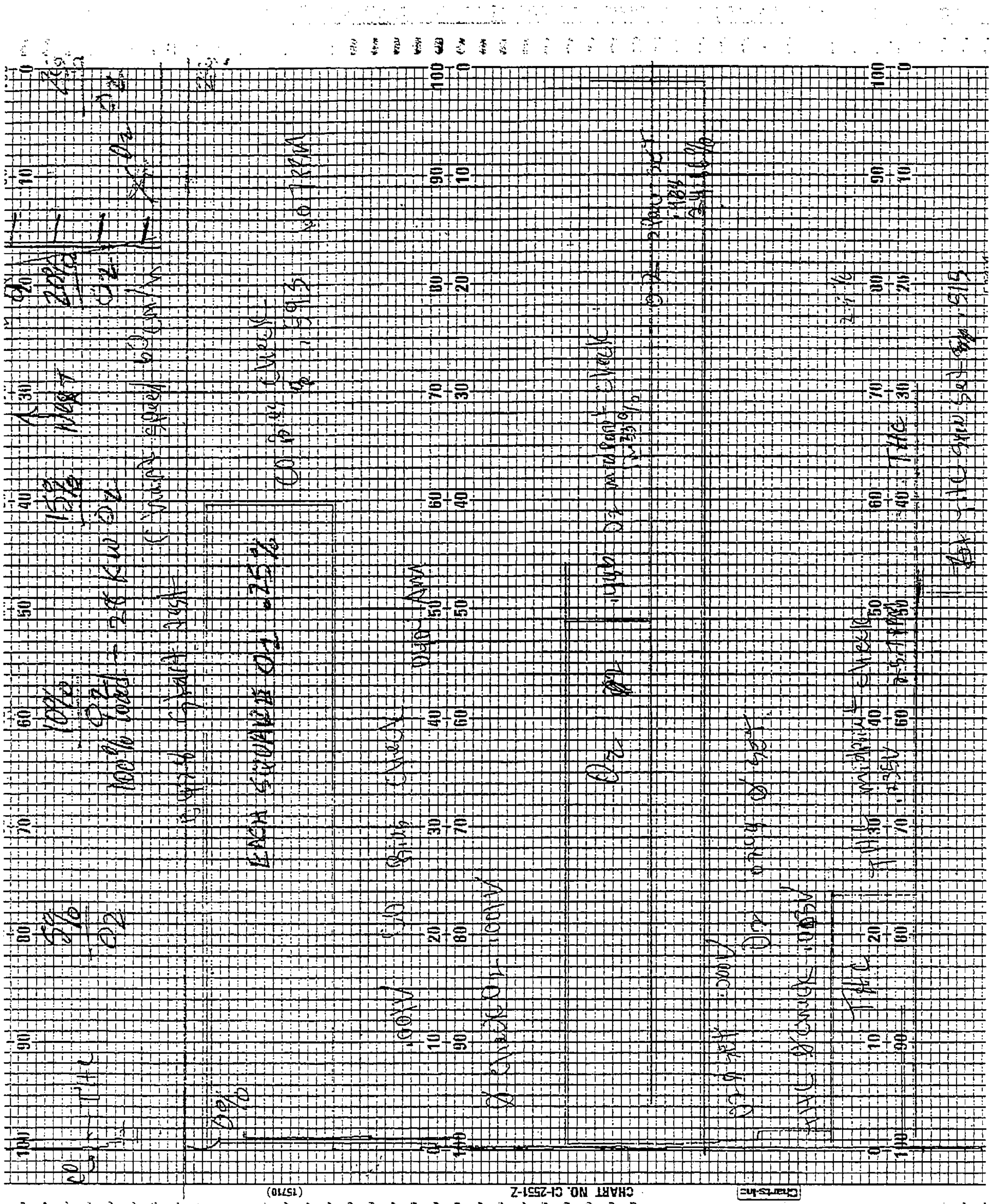

END - Smith Hops Iowa Test
6/14/01
NOx, NO, CO_2

APPENDIX C2

O2, THC, and CO Gas Analyzer Strip Charts



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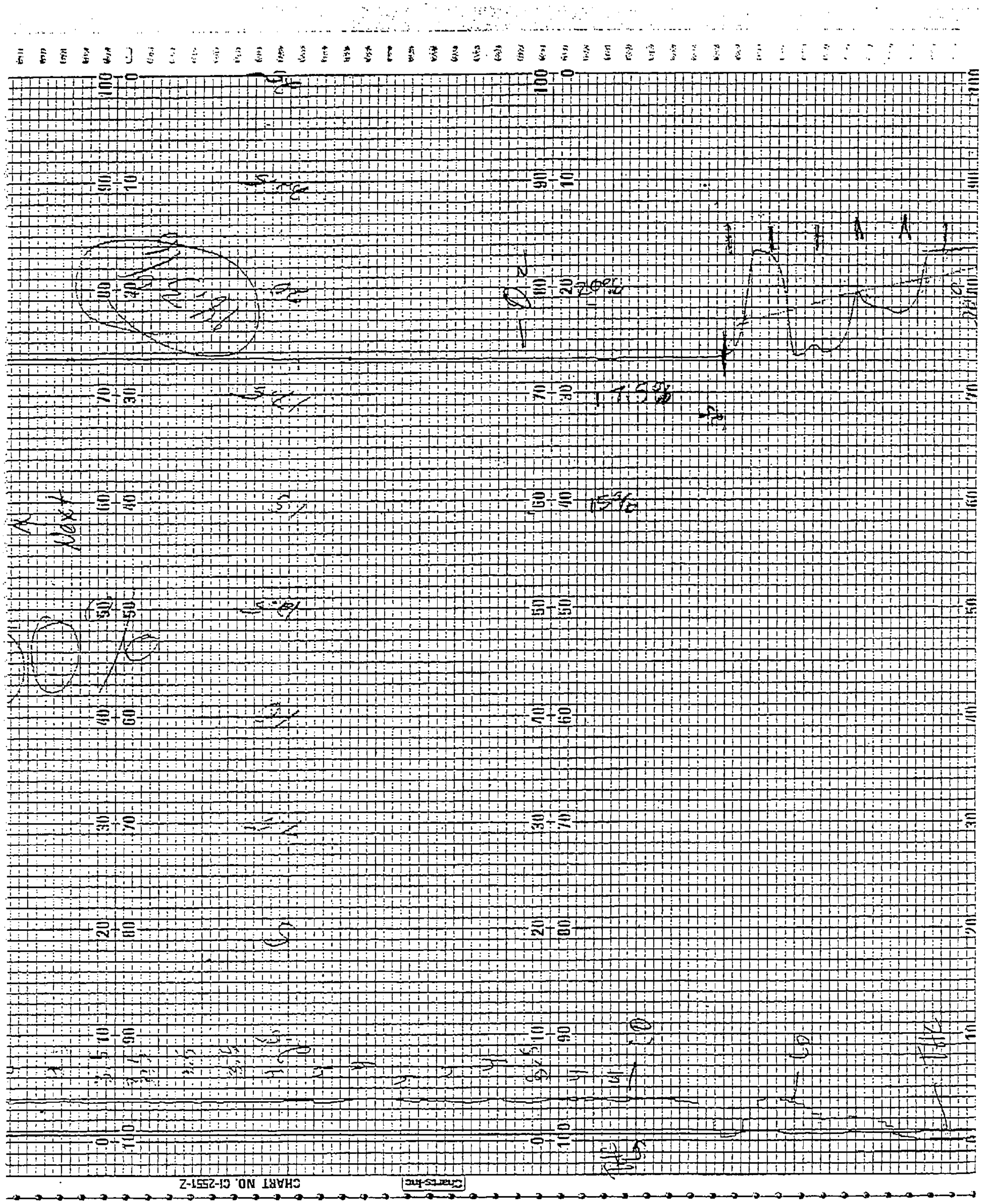
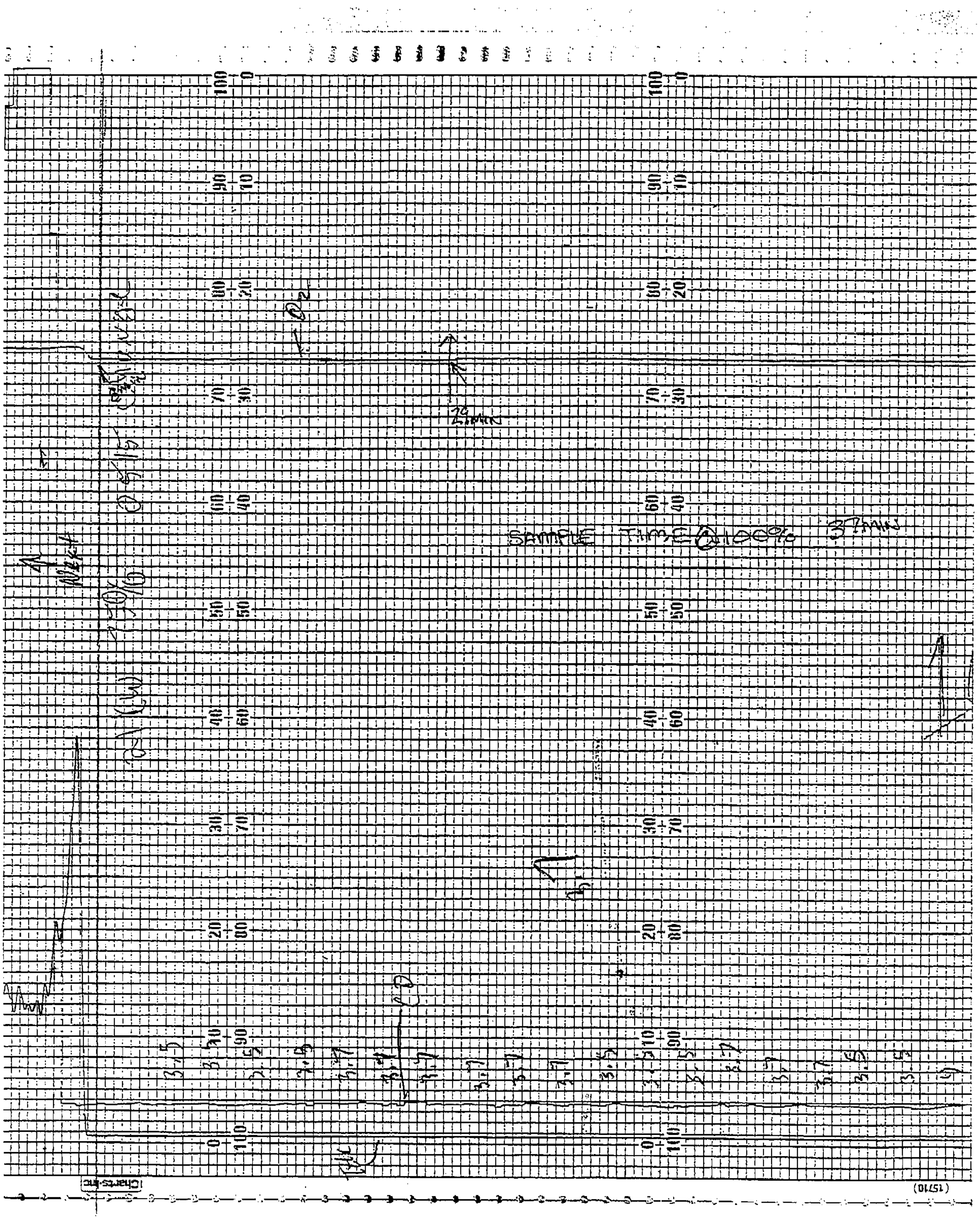
(15710)
EACH SQUARE O2 .25%

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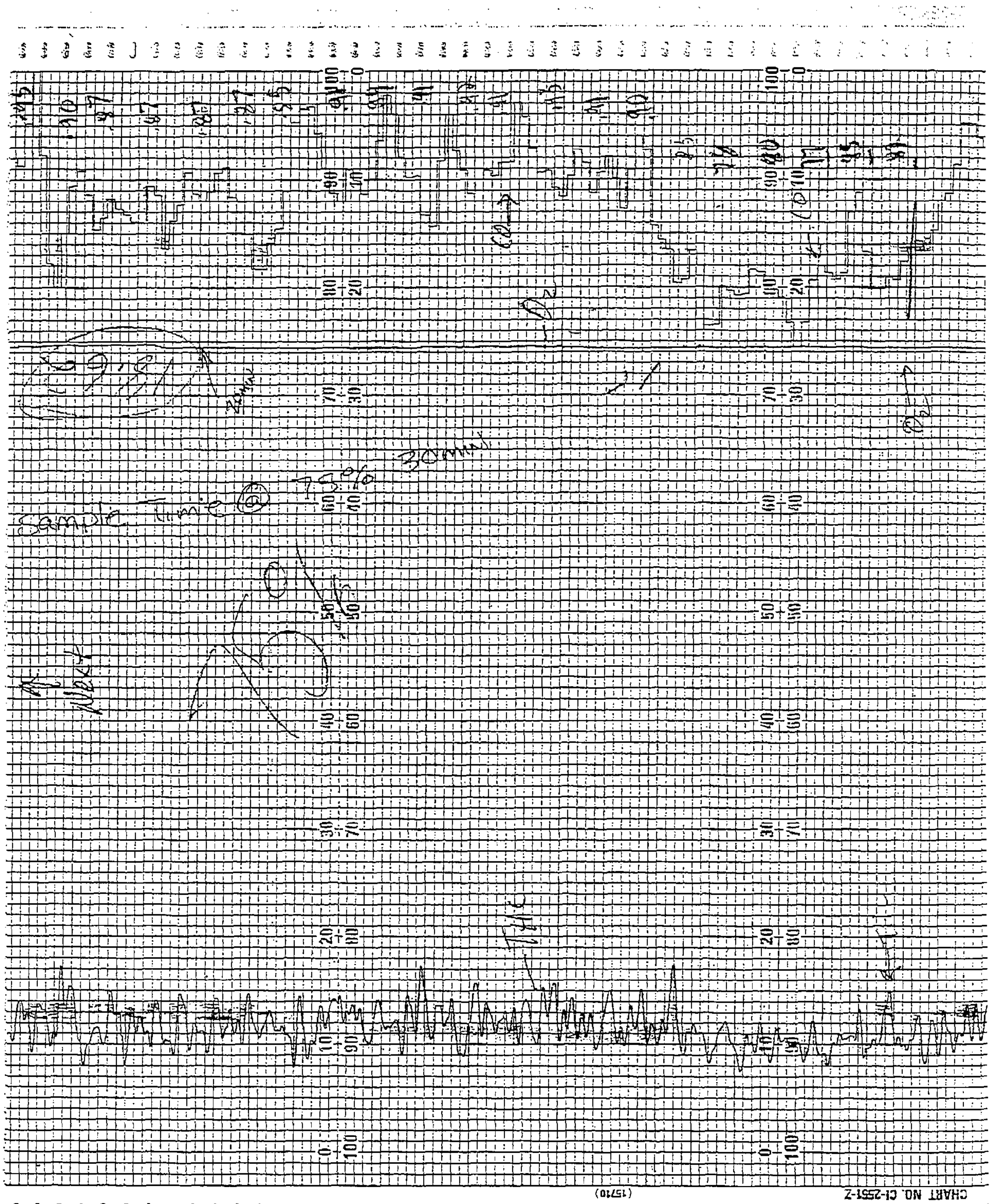
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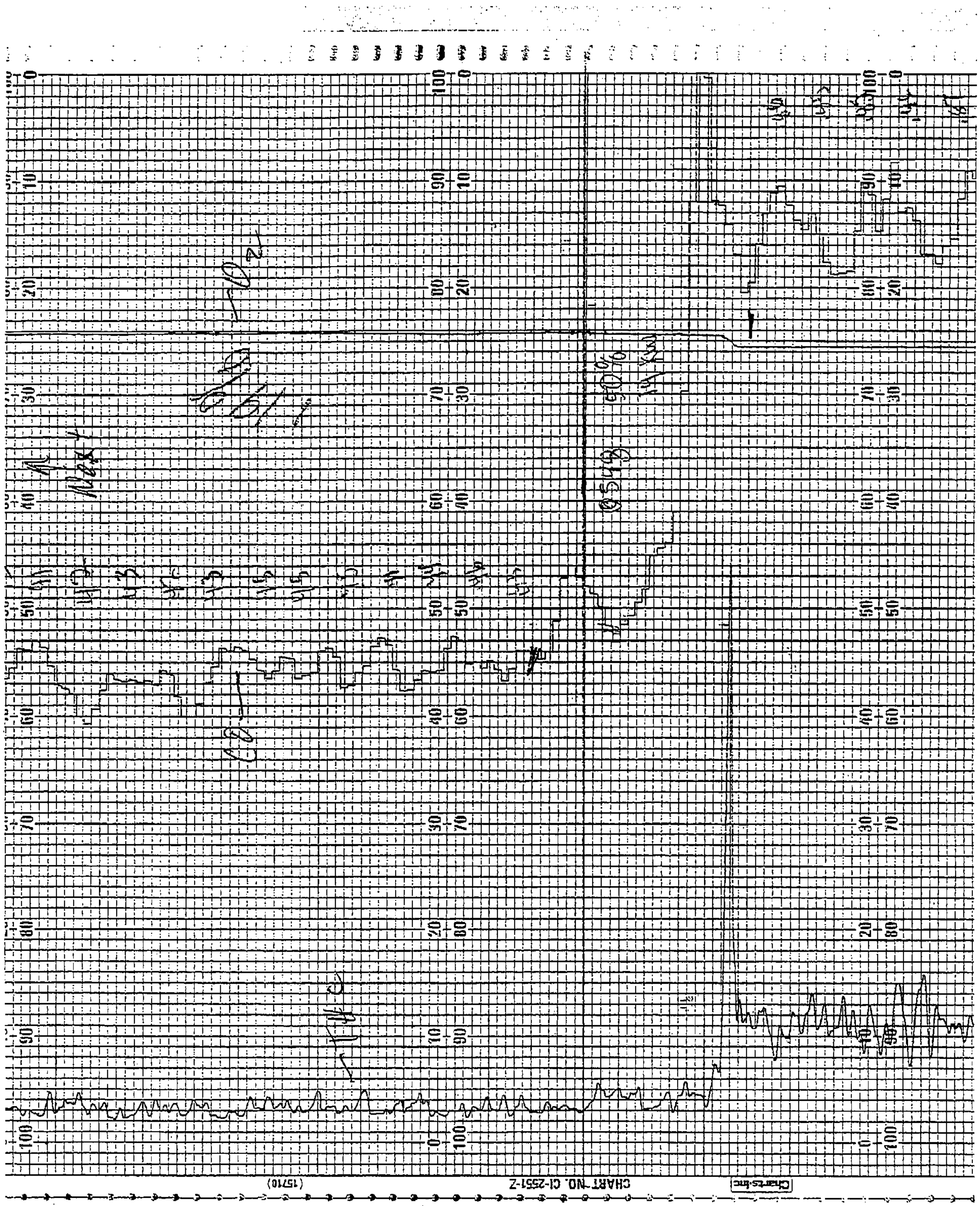
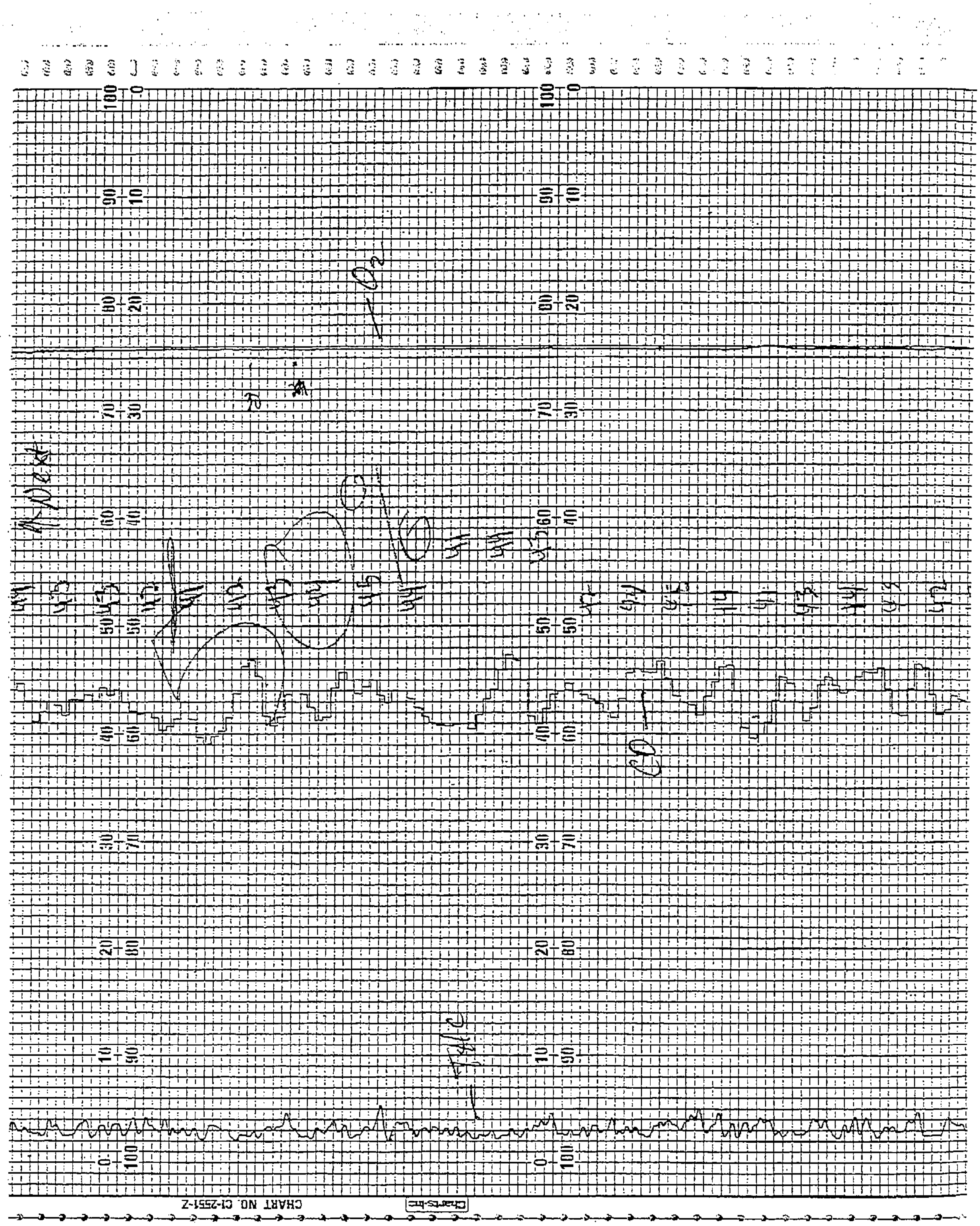
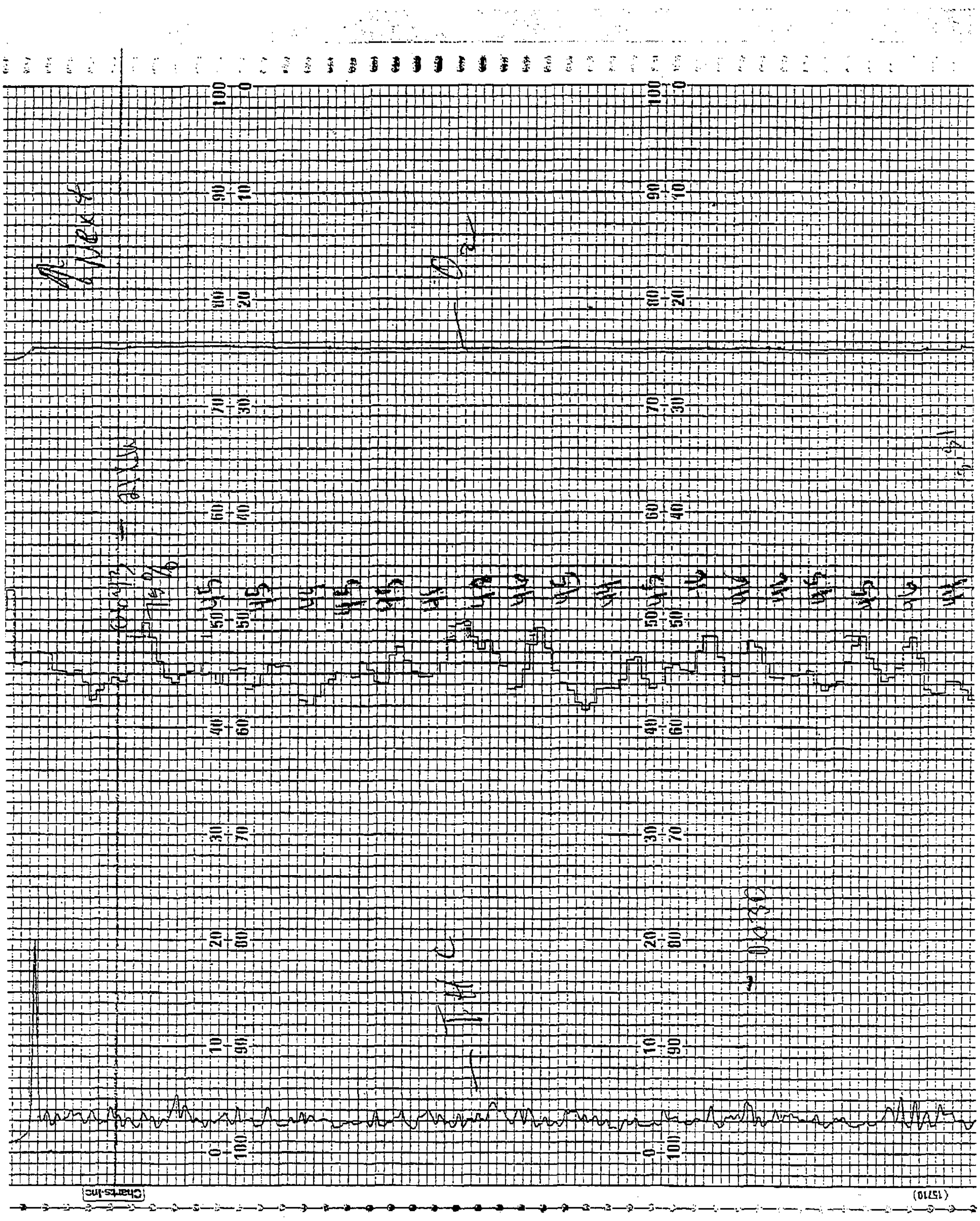
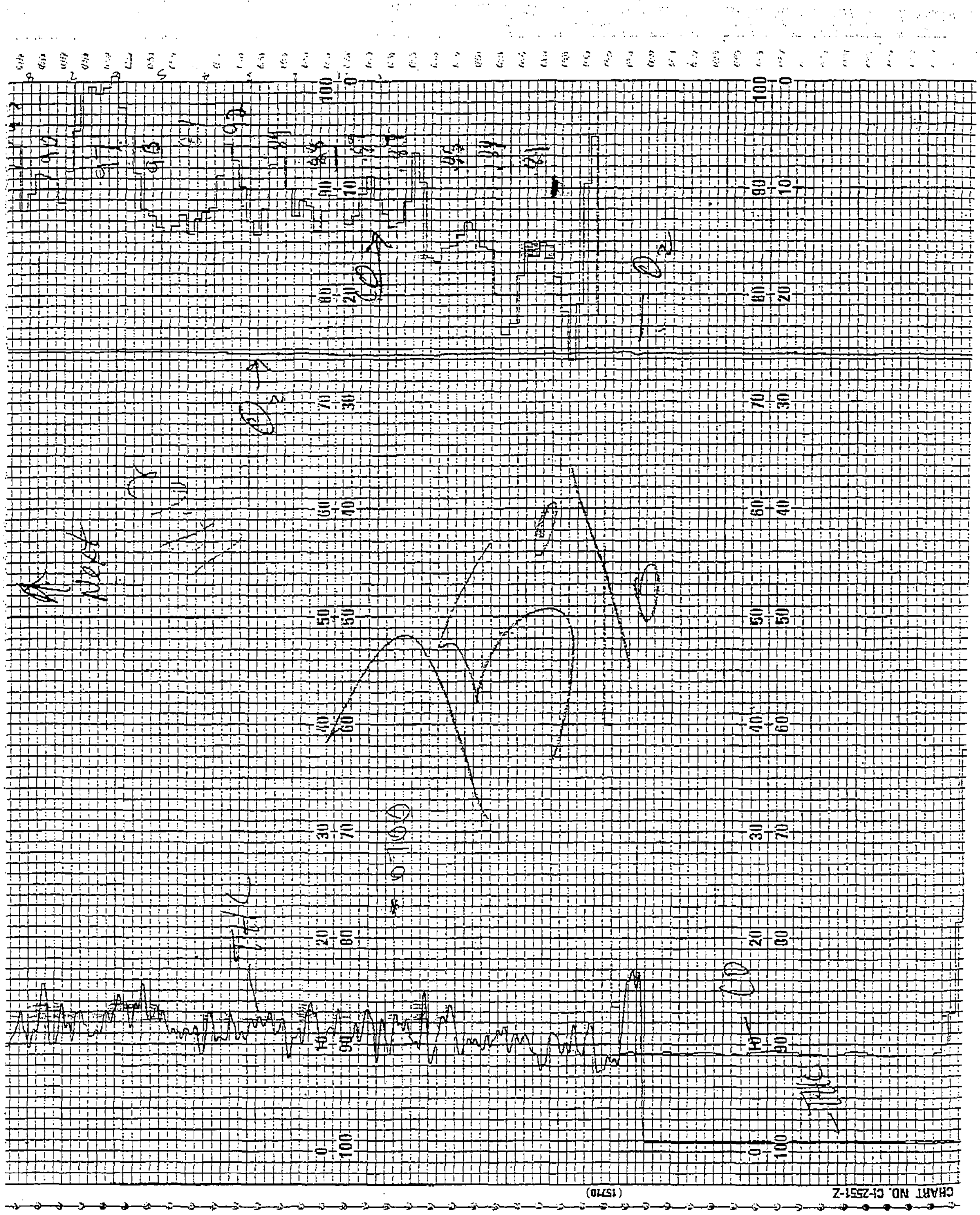
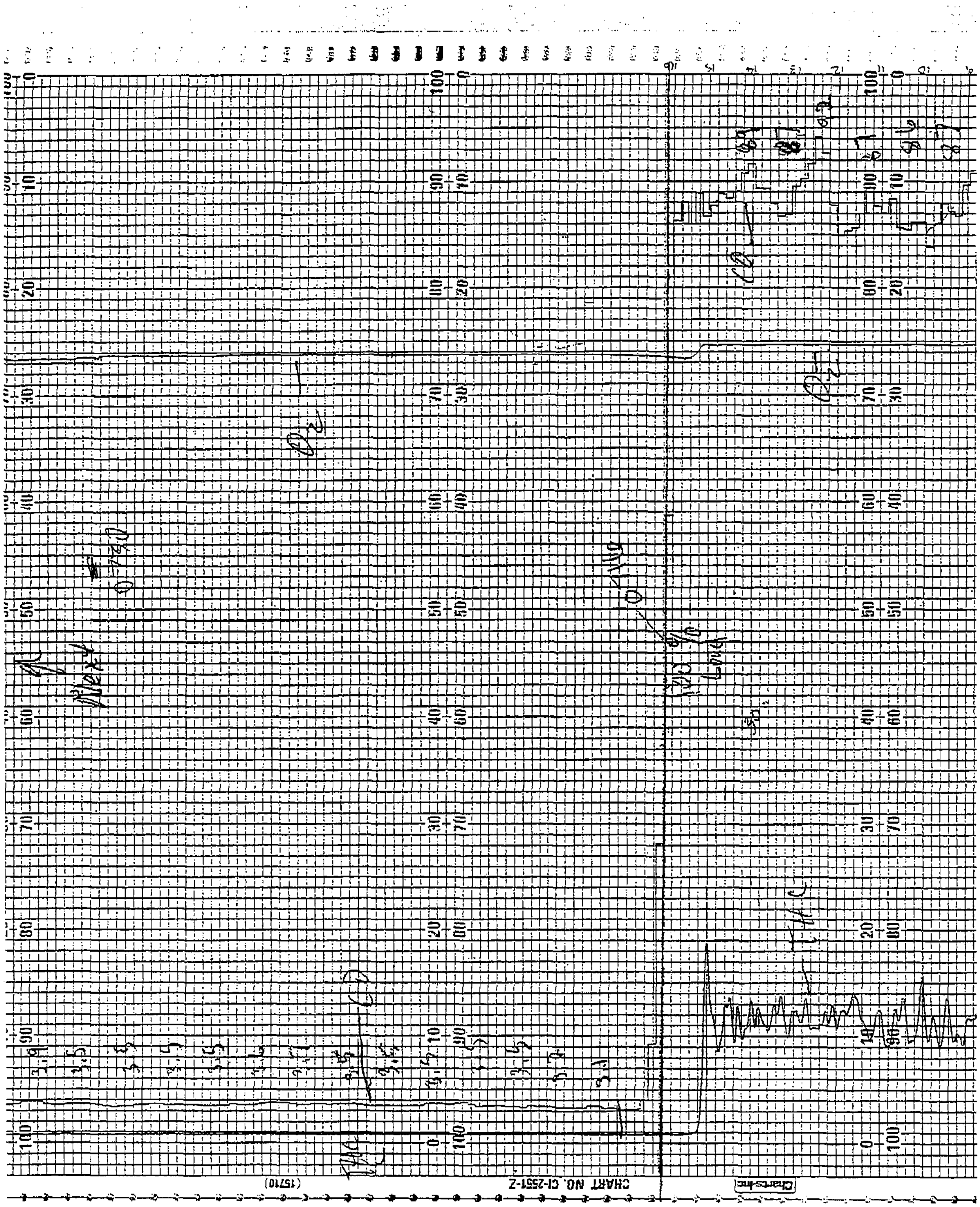
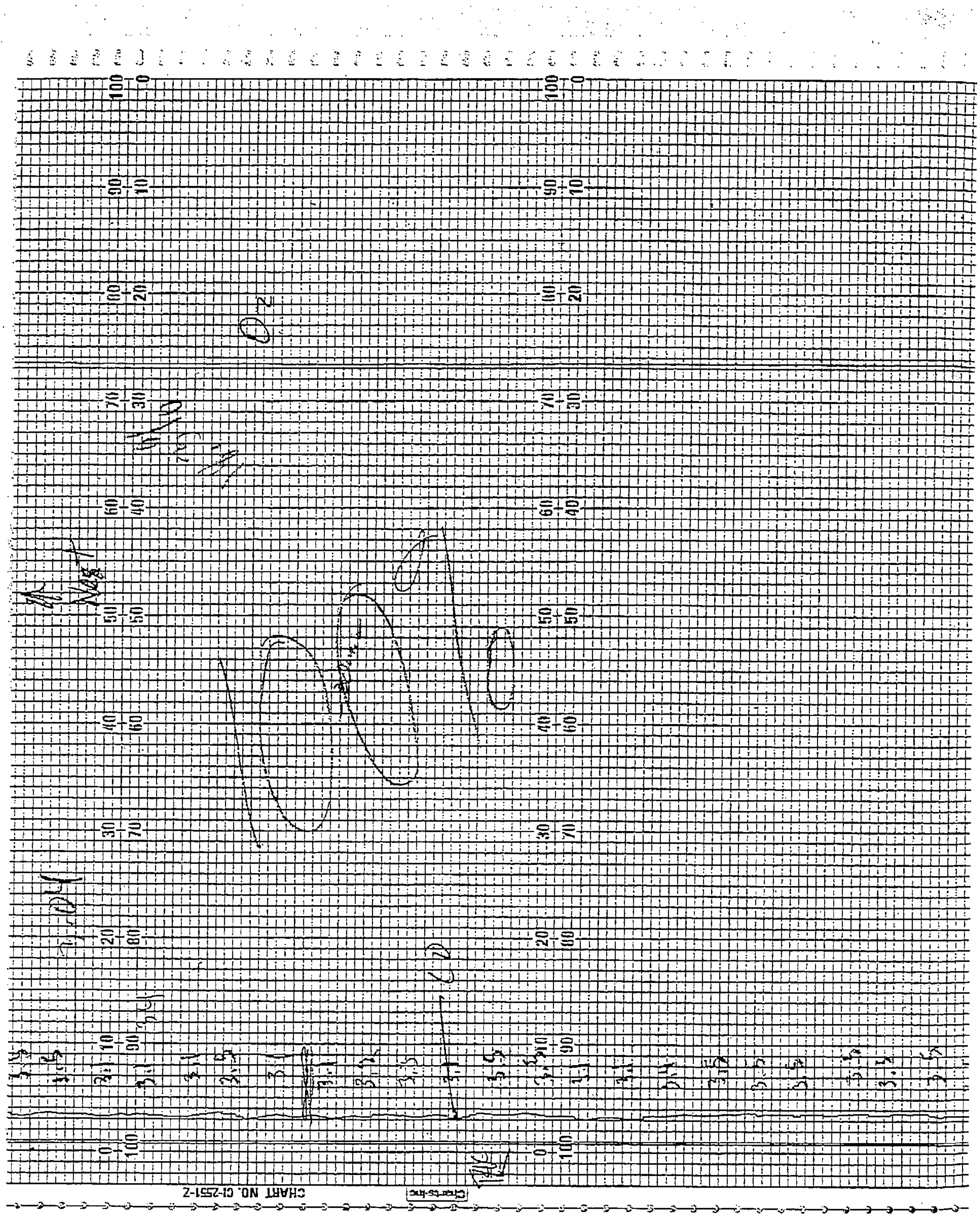


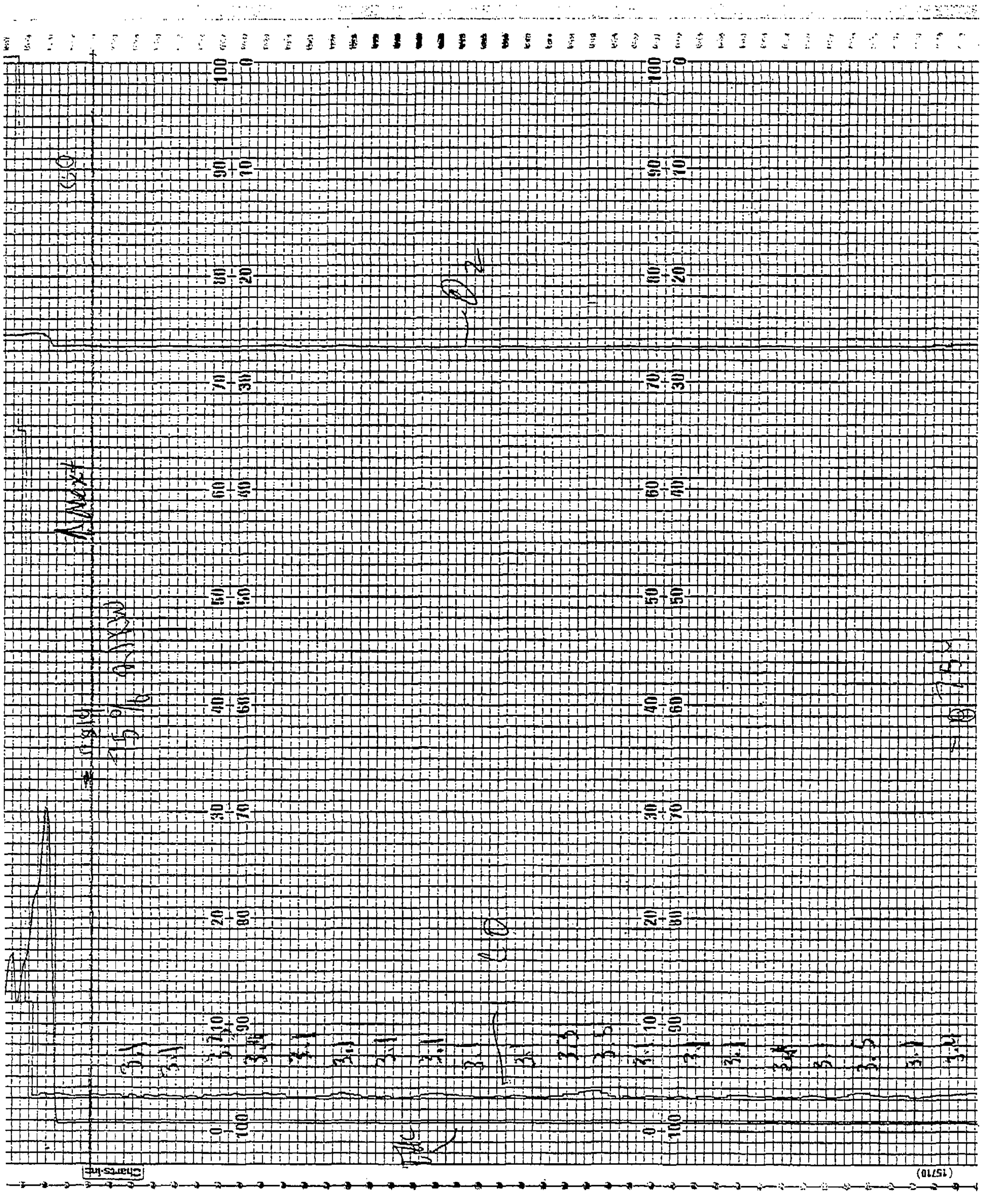


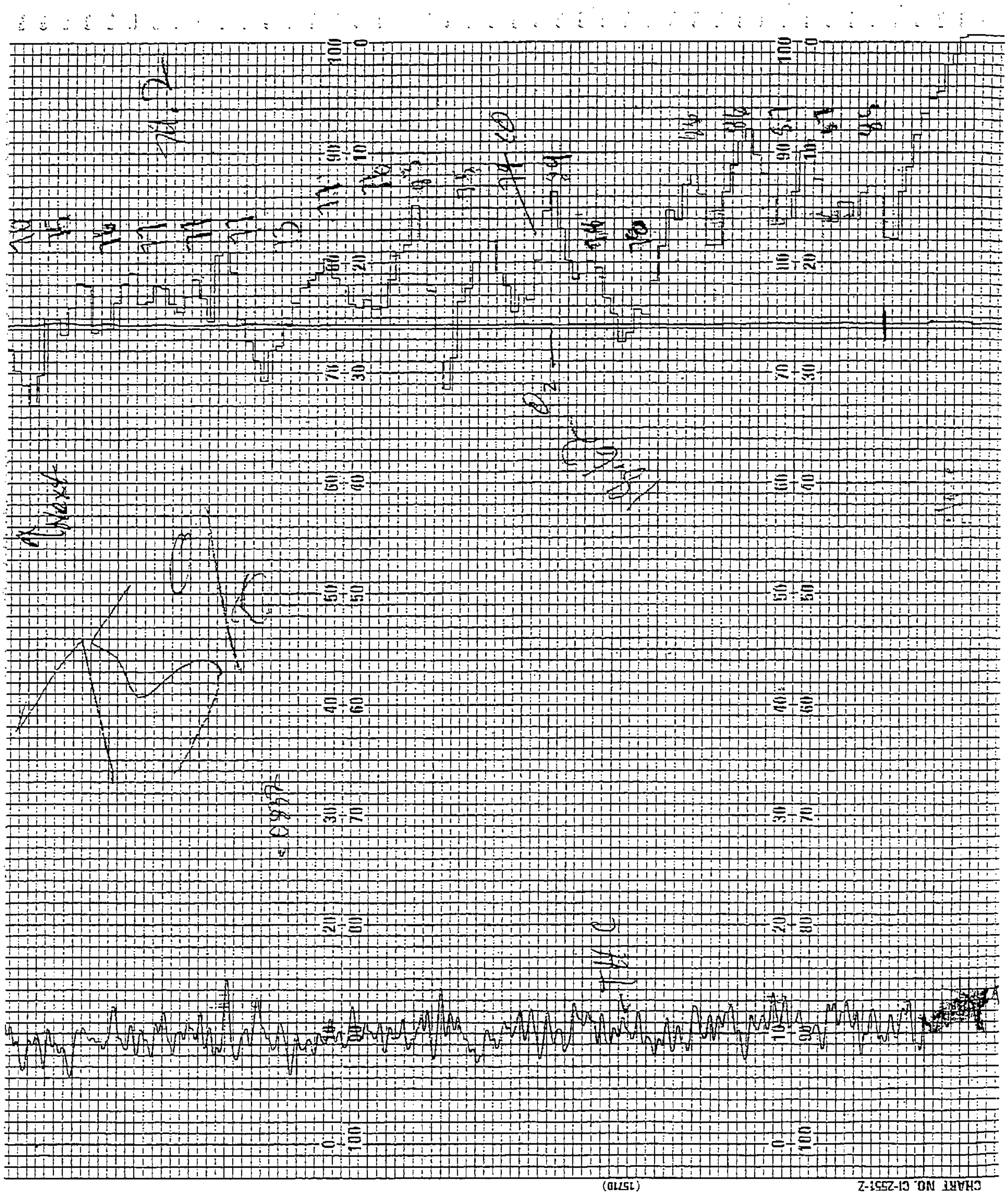


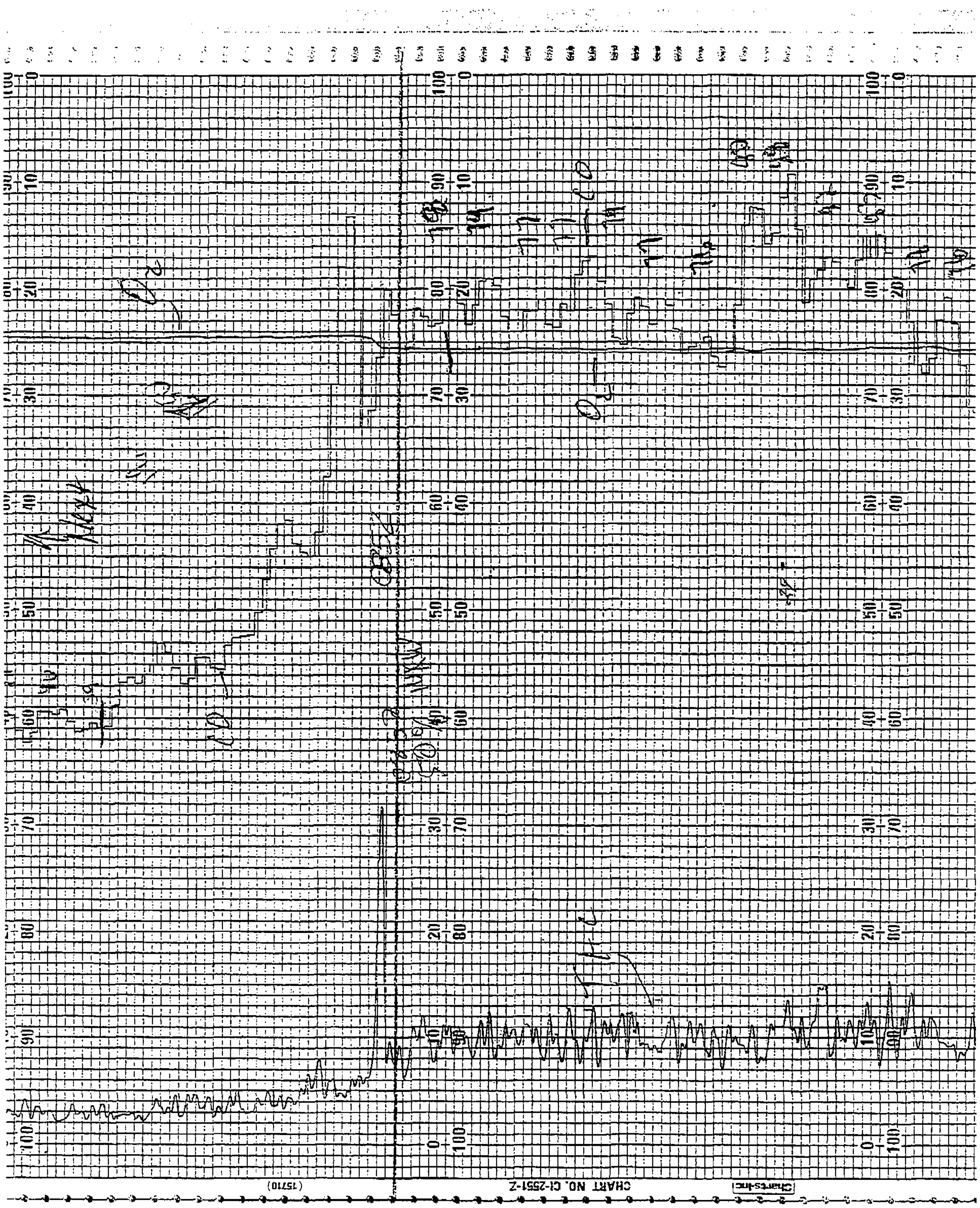


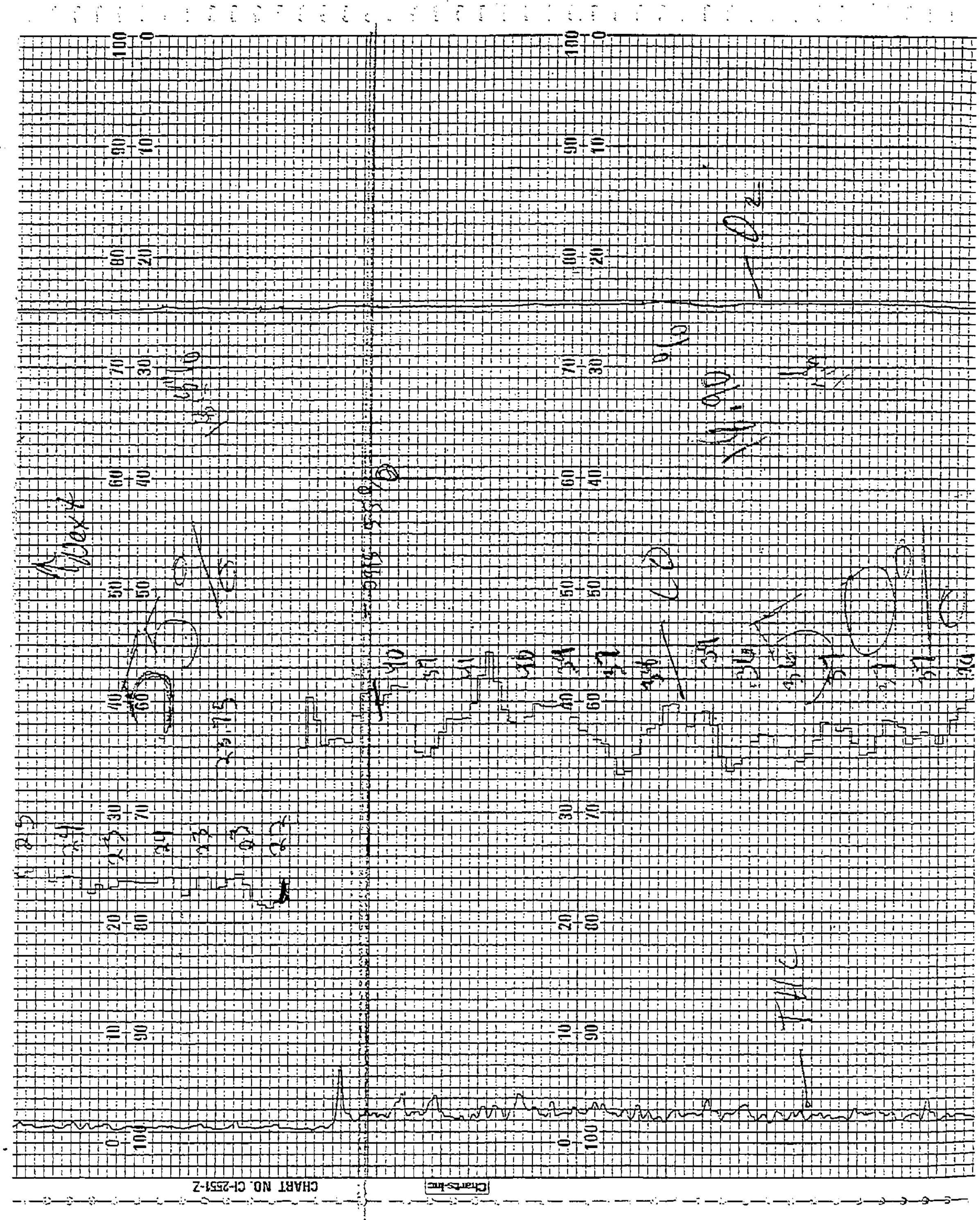


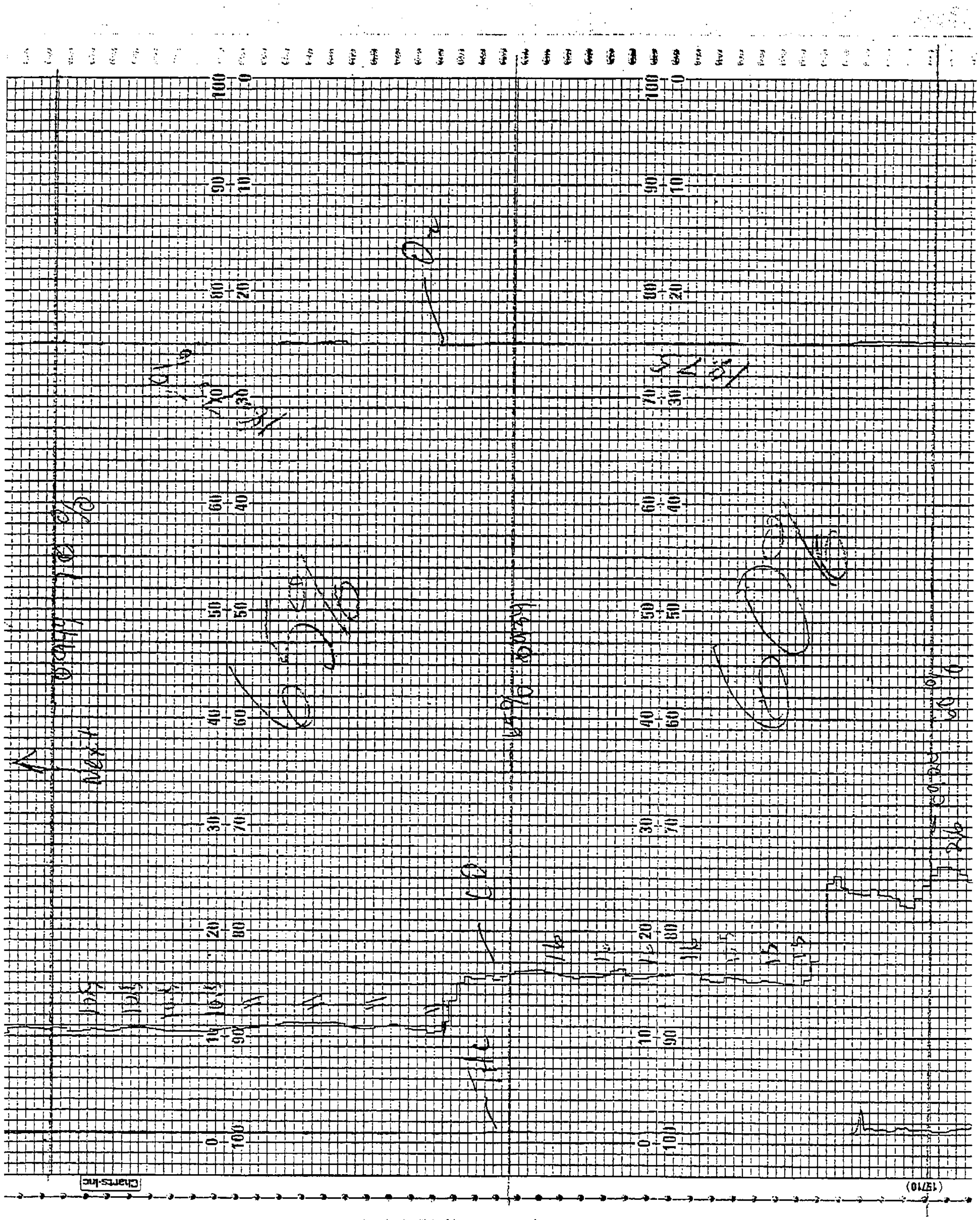


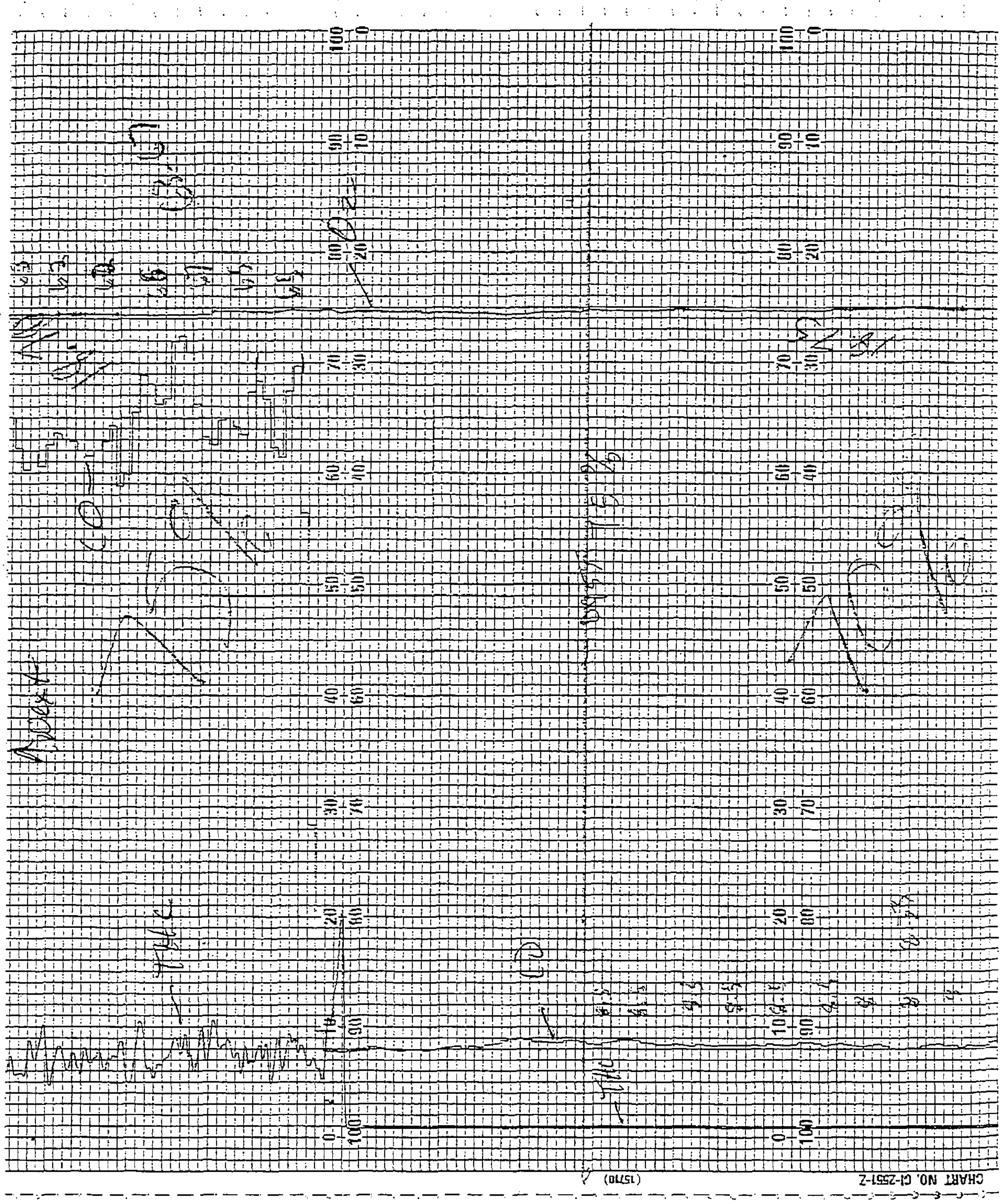












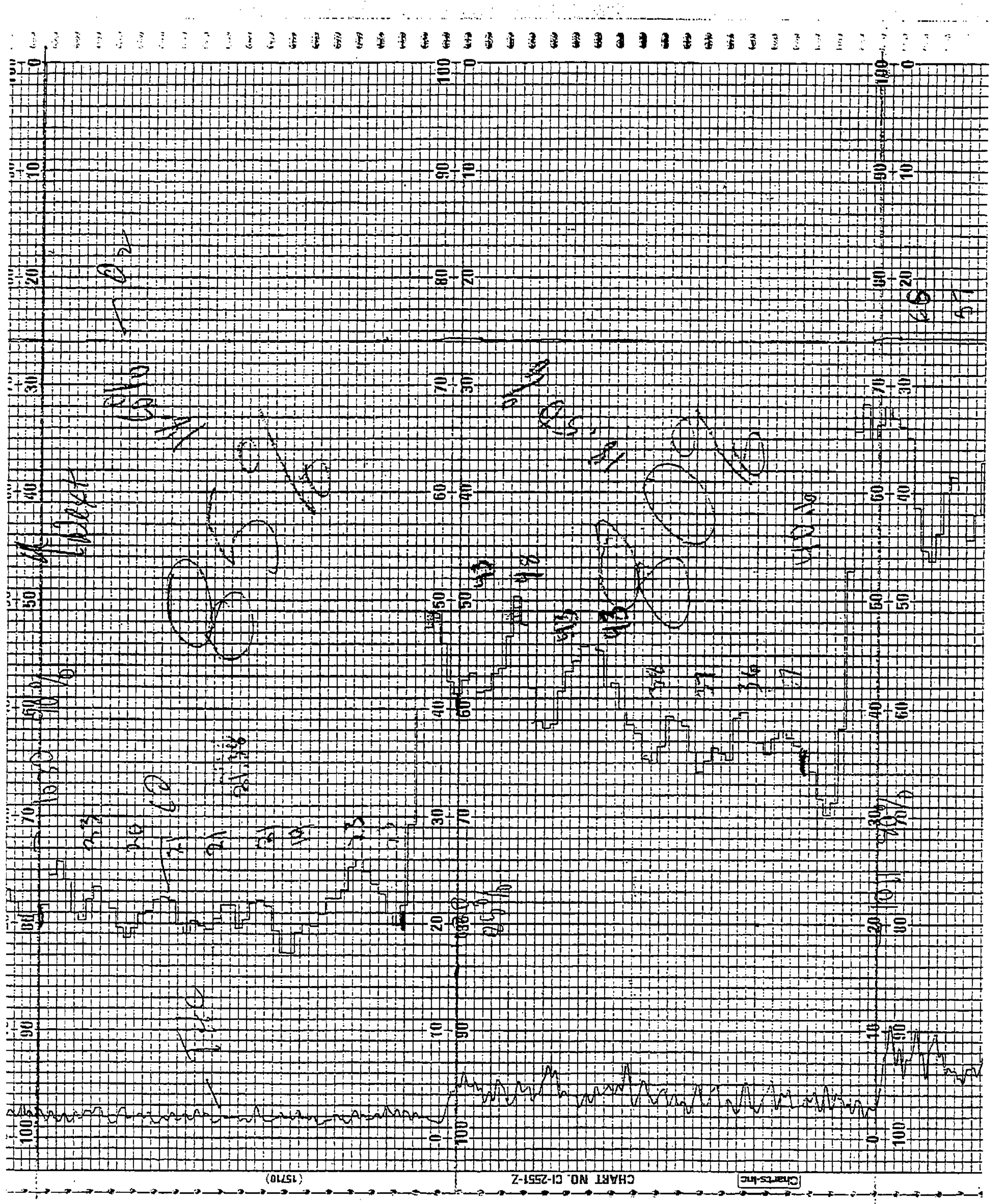
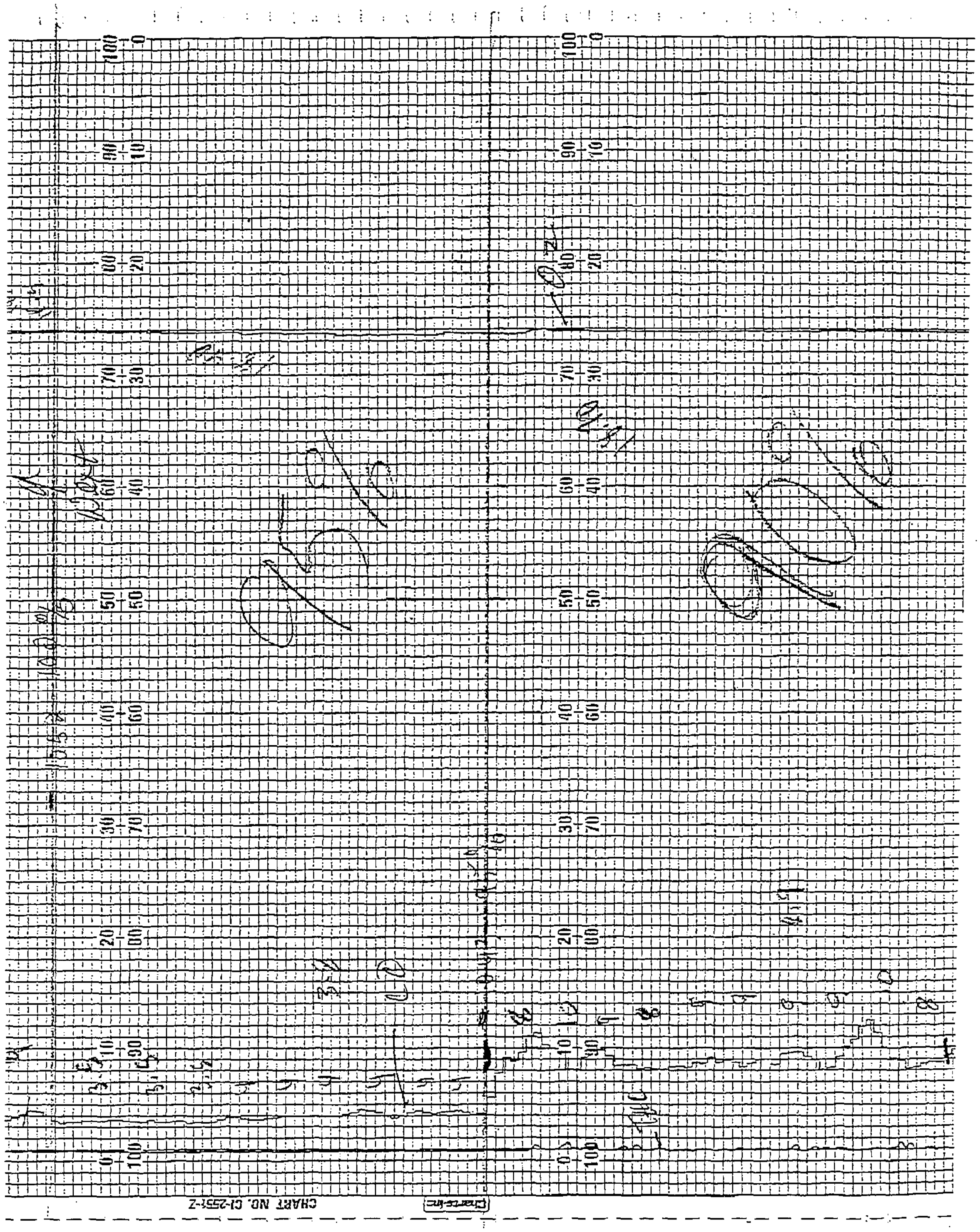
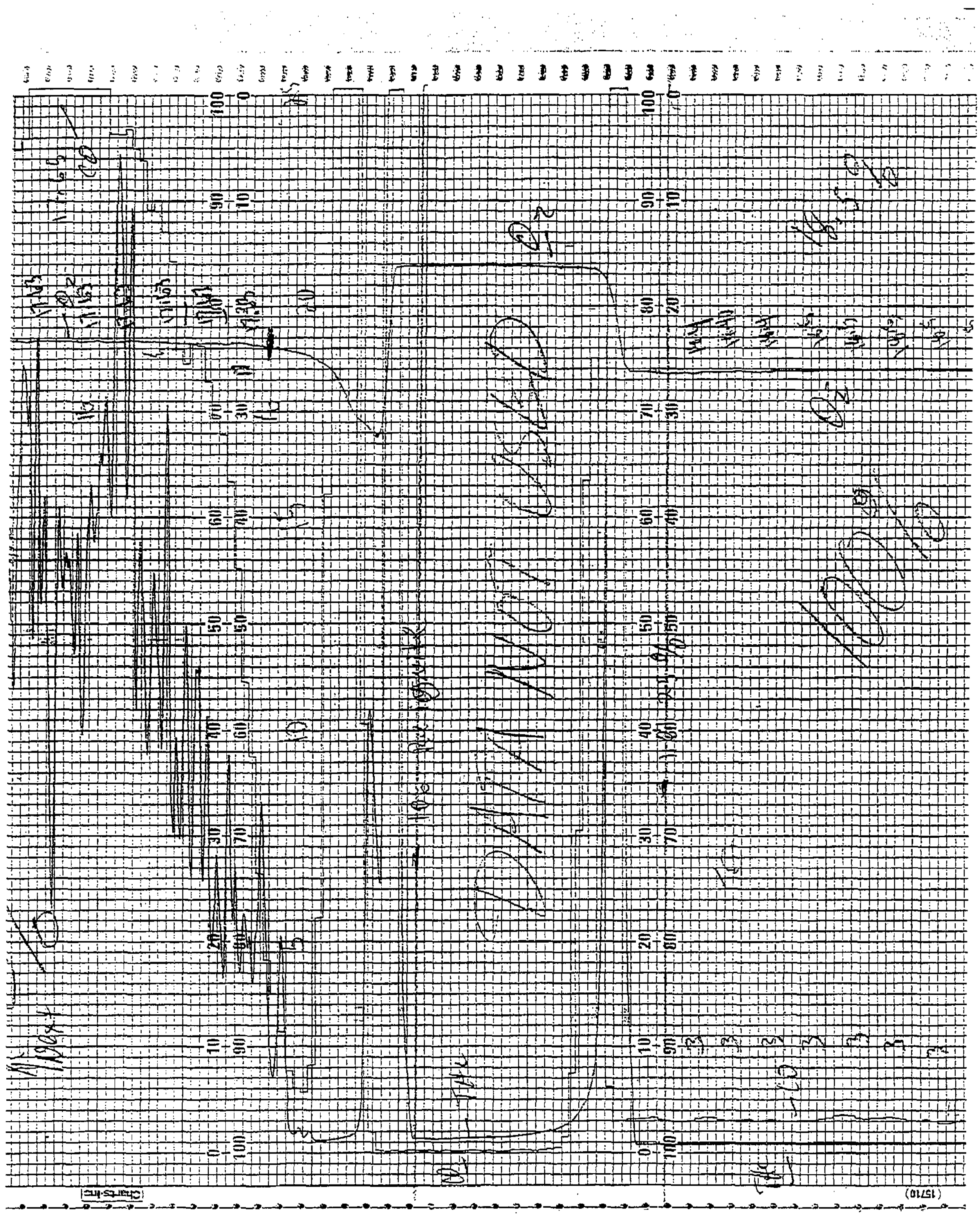
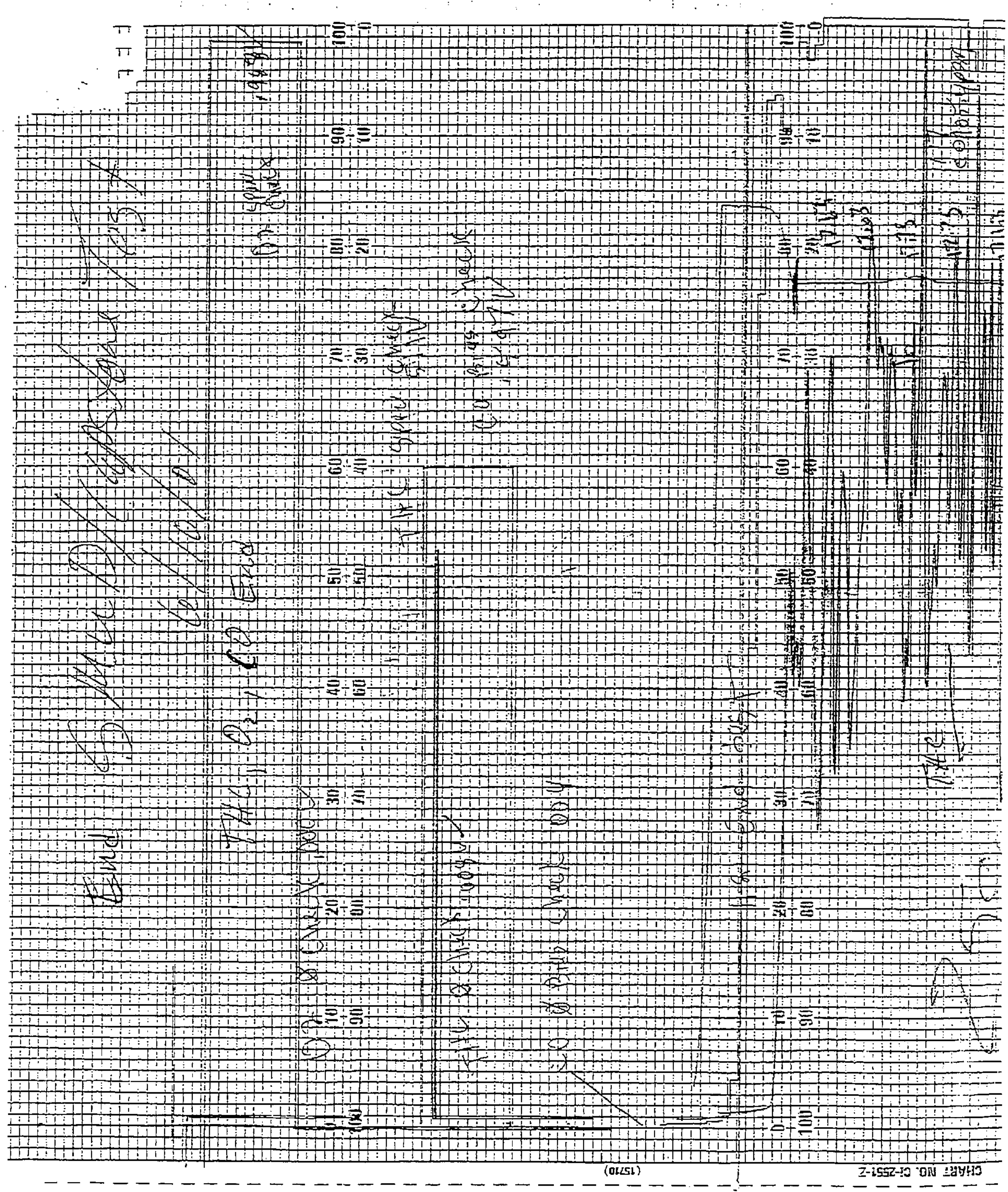


CHART NO. CI-2551-Z
Charts-Inc







APPENDIX D

Microturbine Data Collected
and
Provided by SMUD

Table D1 – 100% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	4:30:02	1098	68.4	14.6	108	28000
06/10/2001	4:30:04	1100	68.4	14.6	107	28000
06/10/2001	4:30:04	1100	68.4	14.6	107	28000
06/10/2001	4:30:18	1099	67.8	14.6	107	28000
06/10/2001	4:30:22	1100	67.8	14.6	107	28000
06/10/2001	4:30:28	1097	67.8	14.6	107	28000
06/10/2001	4:30:30	1099	67.6	14.6	107	28000
06/10/2001	4:30:30	1099	67.6	14.6	107	28000
06/10/2001	4:30:42	1098	67.5	14.6	106	28000
06/10/2001	4:30:48	1098	67.5	14.6	107	28000
06/10/2001	4:30:52	1100	67.5	14.6	107	28000
06/10/2001	4:30:58	1098	67.5	14.6	107	28000
06/10/2001	4:31:02	1099	67.4	14.6	107	28000
06/10/2001	4:31:08	1099	67.4	14.6	107	28000
06/10/2001	4:31:12	1098	67.4	14.6	107	28000
06/10/2001	4:31:18	1099	67.4	14.6	107	28000
06/10/2001	4:31:22	1100	67.4	14.6	106	28000
06/10/2001	4:31:28	1100	67.4	14.6	106	28000
06/10/2001	4:31:32	1097	67.5	14.6	107	28000
06/10/2001	4:31:38	1098	67.2	14.6	108	28000
06/10/2001	4:31:42	1102	67.1	14.6	106	28000
06/10/2001	4:31:46	1098	67.1	14.6	106	28000
06/10/2001	4:31:46	1098	67.1	14.6	106	28000
06/10/2001	4:31:58	1099	67	14.6	107	28000
06/10/2001	4:32:02	1099	67	14.6	107	28000
06/10/2001	4:32:08	1099	67	14.6	106	28000
06/10/2001	4:32:12	1099	67.1	14.6	106	28000
06/10/2001	4:32:18	1099	67.2	14.6	107	28000
06/10/2001	4:32:22	1099	67.4	14.6	106	28000
06/10/2001	4:32:28	1097	67.4	14.6	107	28000
06/10/2001	4:32:32	1100	67.4	14.6	107	28000
06/10/2001	4:32:38	1102	67.4	14.6	106	28000
06/10/2001	4:32:42	1098	67.4	14.6	107	28000
06/10/2001	4:32:48	1099	67.6	14.6	106	28000
06/10/2001	4:32:52	1099	67.9	14.6	106	28000
06/10/2001	4:32:58	1099	68	14.6	107	28000
06/10/2001	4:33:02	1098	68	14.6	107	28000

Table D1 – 100% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	4:33:08	1098	68	14.6	108	28000
06/10/2001	4:33:12	1099	68	14.6	107	28000
06/10/2001	4:33:18	1100	67.6	14.6	106	28000
06/10/2001	4:33:22	1099	67.6	14.6	107	28000
06/10/2001	4:33:28	1099	67.5	14.6	107	28000
06/10/2001	4:33:32	1099	67.2	14.6	106	28000
06/10/2001	4:33:38	1100	67.1	14.6	107	28000
06/10/2001	4:33:42	1100	67.1	14.6	106	28000
06/10/2001	4:33:48	1098	67.1	14.6	107	28000
06/10/2001	4:33:52	1100	67.1	14.6	106	28000
06/10/2001	4:33:58	1097	66.9	14.6	107	28000
06/10/2001	4:34:02	1100	66.9	14.6	107	28000
06/10/2001	4:34:08	1100	67	14.6	106	28000
06/10/2001	4:34:12	1099	67	14.6	106	28000
06/10/2001	4:34:18	1098	67.1	14.6	107	28000
06/10/2001	4:34:22	1100	67.1	14.6	107	28000
06/10/2001	4:34:28	1098	67.1	14.6	107	28000
06/10/2001	4:34:32	1098	67.2	14.6	107	28000
06/10/2001	4:34:38	1100	67.2	14.6	107	28000
06/10/2001	4:34:42	1098	67.4	14.6	107	28000
06/10/2001	4:34:48	1099	67.4	14.6	107	28000
06/10/2001	4:34:52	1098	67.4	14.6	107	28000
06/10/2001	4:34:58	1097	67.5	14.6	108	28000
06/10/2001	4:35:02	1099	67.8	14.6	107	28000
06/10/2001	4:35:08	1097	68.1	14.6	107	28000
06/10/2001	4:35:12	1100	68.2	14.6	107	28000
06/10/2001	4:35:18	1098	68.2	14.6	108	28000
06/10/2001	4:35:22	1099	68.4	14.6	108	28000
06/10/2001	4:35:24	1099	68.4	14.6	108	28000
06/10/2001	4:35:32	1099	68.2	14.6	107	28000
06/10/2001	4:35:38	1100	68.1	14.6	106	28000
06/10/2001	4:35:42	1097	68	14.6	108	28000
06/10/2001	4:35:48	1099	68	14.6	108	28000
06/10/2001	4:35:52	1100	68	14.6	107	28000
06/10/2001	4:35:58	1098	67.9	14.6	107	28000
06/10/2001	4:36:02	1100	67.6	14.6	107	28000
06/10/2001	4:36:08	1099	67.6	14.6	106	28000

Table D1 – 100% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	4:36:12	1099	67.6	14.6	106	28000
06/10/2001	4:36:18	1099	67.6	14.6	106	28000
06/10/2001	4:36:22	1098	67.6	14.6	107	28000
06/10/2001	4:36:28	1100	67.8	14.6	107	28000
06/10/2001	4:36:32	1098	68	14.6	108	28000
06/10/2001	4:36:38	1101	68.4	14.6	106	28000
06/10/2001	4:36:42	1099	68.6	14.6	106	28000
06/10/2001	4:36:48	1099	68.9	14.6	106	28000
06/10/2001	4:36:52	1098	69	14.6	108	28000
06/10/2001	4:36:58	1099	68.9	14.6	107	28000
06/10/2001	4:37:02	1099	68.8	14.6	107	28000
06/10/2001	4:37:08	1100	68.5	14.6	106	28000
06/10/2001	4:37:12	1099	68.4	14.6	107	28000
06/10/2001	4:37:18	1100	68.2	14.6	106	28000
06/10/2001	4:37:22	1098	68.1	14.6	107	28000
06/10/2001	4:37:28	1100	68	14.6	106	28000
06/10/2001	4:37:32	1098	67.8	14.6	107	28000
06/10/2001	4:37:38	1100	67.5	14.6	105	28000
06/10/2001	4:37:42	1098	67.5	14.6	106	28000
06/10/2001	4:37:48	1098	67.8	14.6	107	28000
06/10/2001	4:37:52	1099	68	14.6	107	28000
06/10/2001	4:37:58	1100	68.2	14.6	106	28000
06/10/2001	4:38:02	1099	68.2	14.6	106	28000
06/10/2001	4:38:04	1099	68.2	14.6	107	28000
06/10/2001	4:38:04	1099	68.2	14.6	107	28000
06/10/2001	4:38:18	1100	68.2	14.6	106	28000
06/10/2001	4:38:22	1099	68.2	14.6	107	28000
06/10/2001	4:38:28	1102	68.2	14.6	107	28000
06/10/2001	4:38:32	1099	68.4	14.6	106	28000
06/10/2001	4:38:38	1100	68.5	14.6	106	28000
06/10/2001	4:38:40	1098	68.5	14.6	107	28000
06/10/2001	4:38:40	1098	68.5	14.6	107	28000
06/10/2001	4:38:40	1098	68.5	14.6	107	28000
06/10/2001	4:38:58	1098	68.5	14.6	106	28000
06/10/2001	4:39:02	1098	68.4	14.6	107	28000
06/10/2001	4:39:08	1099	68	14.6	107	28000
06/10/2001	4:39:12	1101	67.8	14.6	106	28000

Table D1 – 100% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	4:39:18	1100	67.6	14.6	106	28000
06/10/2001	4:39:22	1098	67.5	14.6	106	28000
06/10/2001	4:39:28	1098	67.4	14.6	106	28000
06/10/2001	4:39:32	1098	67.4	14.6	106	28000
06/10/2001	4:39:38	1097	67.4	14.6	108	28000
06/10/2001	4:39:42	1098	67.4	14.6	108	28000
06/10/2001	4:39:48	1097	67.5	14.6	107	28000
06/10/2001	4:39:52	1100	67.5	14.6	106	28000
06/10/2001	4:39:56	1099	67.8	14.6	106	28000
06/10/2001	4:39:56	1099	67.8	14.6	106	28000
06/10/2001	4:40:08	1099	67.9	14.6	106	28000
06/10/2001	4:40:12	1100	67.9	14.6	106	28000
06/10/2001	4:40:18	1098	67.9	14.6	107	28000
06/10/2001	4:40:18	1098	67.9	14.6	107	28000
06/10/2001	4:40:28	1100	68.1	14.6	106	28000
06/10/2001	4:40:30	1098	68.1	14.6	107	28000
06/10/2001	4:40:30	1098	68.1	14.6	107	28000
06/10/2001	4:40:42	1100	68	14.6	106	28000
06/10/2001	4:40:48	1101	67.9	14.6	106	28000
06/10/2001	4:40:50	1098	67.9	14.6	107	28000
06/10/2001	4:40:58	1101	67.8	14.6	106	28000
06/10/2001	4:41:02	1099	67.8	14.6	106	28000
06/10/2001	4:41:08	1099	67.6	14.6	106	28000
06/10/2001	4:41:12	1097	67.6	14.6	107	28000
06/10/2001	4:41:18	1099	67.6	14.6	106	28000
06/10/2001	4:41:22	1098	67.8	14.6	107	28000
06/10/2001	4:41:28	1098	67.6	14.6	108	28000
06/10/2001	4:41:32	1099	67.5	14.6	108	28000
06/10/2001	4:41:38	1100	67.4	14.6	106	28000
06/10/2001	4:41:42	1099	67.2	14.6	107	28000
06/10/2001	4:41:48	1100	67.1	14.6	107	28000
06/10/2001	4:41:52	1099	67.1	14.6	107	28000
06/10/2001	4:41:58	1098	67	14.6	107	28000
06/10/2001	4:42:02	1099	67.1	14.6	107	28000
06/10/2001	4:42:08	1102	67.4	14.6	106	28000
06/10/2001	4:42:12	1099	67.6	14.6	107	28000
06/10/2001	4:42:18	1099	68	14.6	107	28000

Table D1 – 100% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	4:42:24	1101	68.2	14.6	106	28000
06/10/2001	4:42:28	1100	68.5	14.6	106	28000
06/10/2001	4:42:32	1097	68.5	14.6	107	28000
06/10/2001	4:42:38	1100	68.6	14.6	106	28000
06/10/2001	4:42:42	1099	68.6	14.6	106	28000
06/10/2001	4:42:42	1099	68.6	14.6	106	28000
06/10/2001	4:42:52	1098	68.6	14.6	107	28000
06/10/2001	4:42:52	1098	68.6	14.6	107	28000
06/10/2001	4:43:02	1101	68.6	14.6	106	28000
06/10/2001	4:43:08	1099	68.9	14.6	106	28000
06/10/2001	4:43:12	1098	69	14.6	107	28000
06/10/2001	4:43:18	1100	69.2	14.6	107	28000
06/10/2001	4:43:22	1101	69.1	14.6	106	28000
06/10/2001	4:43:28	1098	69	14.6	107	28000
06/10/2001	4:43:32	1099	68.6	14.6	107	28000
06/10/2001	4:43:38	1101	68.2	14.6	106	28000
06/10/2001	4:43:42	1099	68.1	14.6	106	28000
06/10/2001	4:43:46	1099	68	14.6	107	28000
06/10/2001	4:43:46	1099	68	14.6	107	28000
06/10/2001	4:43:58	1097	67.5	14.6	107	28000
06/10/2001	4:44:02	1101	67.4	14.6	106	28000
06/10/2001	4:44:06	1100	67.4	14.6	106	28000
06/10/2001	4:44:06	1100	67.4	14.6	106	28000
06/10/2001	4:44:18	1098	67.8	14.6	107	28000
06/10/2001	4:44:22	1098	67.8	14.6	107	28000
06/10/2001	4:44:28	1100	67.8	14.6	107	28000
06/10/2001	4:44:32	1099	67.8	14.6	107	28000
06/10/2001	4:44:38	1098	67.6	14.6	107	28000
06/10/2001	4:44:42	1098	67.6	14.6	107	28000
06/10/2001	4:44:48	1100	67.6	14.6	106	28000
06/10/2001	4:44:52	1099	67.5	14.6	106	28000
06/10/2001	4:44:58	1100	67.5	14.6	106	28000
06/10/2001	4:45:02	1098	67.5	14.6	106	28000
06/10/2001	4:45:08	1098	67.8	14.6	108	28000
06/10/2001	4:45:12	1100	67.9	14.6	107	28000
06/10/2001	4:45:18	1099	68.2	14.6	106	28000
06/10/2001	5:00:56	1099	68.6	14.6	106	28000

Table D1 – 100% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:01:08	1099	68.4	14.6	106	28000
06/10/2001	5:01:14	1098	68.4	14.6	107	28000
06/10/2001	5:01:18	1099	68.2	14.6	107	28000
06/10/2001	5:01:22	1100	68.1	14.6	106	28000
06/10/2001	5:01:28	1098	68	14.6	107	28000
06/10/2001	5:01:32	1100	68.2	14.6	106	28000
06/10/2001	5:01:38	1099	68.2	14.6	107	28000
06/10/2001	5:01:42	1099	68.4	14.6	107	28000
06/10/2001	5:01:44	1101	68.2	14.6	106	28000
06/10/2001	5:01:52	1098	67.9	14.6	106	28000
06/10/2001	5:01:58	1100	67.6	14.6	106	28000
06/10/2001	5:02:02	1097	67.6	14.6	107	28000
06/10/2001	5:02:08	1099	67.8	14.6	107	28000
06/10/2001	5:02:12	1097	68	14.6	107	28000
06/10/2001	5:02:16	1099	68.1	14.6	107	28000
06/10/2001	5:02:16	1099	68.1	14.6	107	28000

Table D2 – 75% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:02:28	1110	68.4	14.6	85	21000
06/10/2001	5:02:34	1100	68.5	14.6	85	21000
06/10/2001	5:02:38	1096	68.6	14.6	86	21000
06/10/2001	5:02:42	1098	68.5	14.6	85	21000
06/10/2001	5:02:42	1098	68.5	14.6	85	21000
06/10/2001	5:02:52	1100	68.8	14.6	84	21000
06/10/2001	5:02:52	1100	68.8	14.6	84	21000
06/10/2001	5:03:02	1101	68.9	14.6	85	21000
06/10/2001	5:03:08	1095	69	14.6	86	21000
06/10/2001	5:03:12	1098	69	14.6	86	21000
06/10/2001	5:03:18	1100	69.1	14.6	85	21000
06/10/2001	5:03:22	1097	69.2	14.6	86	21000
06/10/2001	5:03:28	1100	69.5	14.6	85	21000
06/10/2001	5:03:32	1099	69.8	14.6	85	21000
06/10/2001	5:03:38	1099	70	14.6	86	21000
06/10/2001	5:03:42	1101	70.1	14.6	85	21000
06/10/2001	5:03:48	1098	70.4	14.6	86	21000
06/10/2001	5:03:52	1102	70.4	14.6	85	21000
06/10/2001	5:03:58	1099	70.4	14.6	85	21000
06/10/2001	5:04:02	1096	70.2	14.6	87	21000
06/10/2001	5:04:08	1102	70	14.6	85	21000
06/10/2001	5:04:12	1098	70	14.6	86	21000
06/10/2001	5:04:18	1102	69.8	14.6	85	21000
06/10/2001	5:04:22	1098	69.8	14.6	86	21000
06/10/2001	5:04:28	1099	69.6	14.6	86	21000
06/10/2001	5:04:32	1099	69.5	14.6	86	21000
06/10/2001	5:04:38	1096	69.4	14.6	87	21000
06/10/2001	5:04:42	1098	69.2	14.6	86	21000
06/10/2001	5:04:48	1099	69.4	14.6	85	21000
06/10/2001	5:04:52	1099	69.2	14.6	86	21000
06/10/2001	5:04:58	1101	69.2	14.6	85	21000
06/10/2001	5:05:02	1099	69.4	14.6	85	21000
06/10/2001	5:05:08	1099	69.4	14.6	86	21000
06/10/2001	5:05:12	1100	69.2	14.6	85	21000
06/10/2001	5:05:18	1099	69.4	14.6	85	21000
06/10/2001	5:05:22	1098	69.5	14.6	86	21000
06/10/2001	5:05:22	1098	69.5	14.6	86	21000

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Table D2 – 75% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:05:32	1098	69.5	14.6	86	21000
06/10/2001	5:05:38	1100	69.4	14.6	85	21000
06/10/2001	5:05:42	1098	69.2	14.6	86	21000
06/10/2001	5:05:48	1100	69	14.6	86	21000
06/10/2001	5:05:52	1099	69	14.6	85	21000
06/10/2001	5:05:58	1099	69	14.6	86	21000
06/10/2001	5:06:02	1098	68.9	14.6	86	21000
06/10/2001	5:06:08	1098	68.8	14.6	86	21000
06/10/2001	5:06:12	1099	68.8	14.6	85	21000
06/10/2001	5:06:18	1100	68.8	14.6	85	21000
06/10/2001	5:06:22	1100	68.9	14.6	85	21000
06/10/2001	5:06:28	1099	69.1	14.6	86	21000
06/10/2001	5:06:32	1100	69.1	14.6	84	21000
06/10/2001	5:06:38	1099	69.1	14.6	85	21000
06/10/2001	5:06:40	1095	69.1	14.6	87	21000
06/10/2001	5:06:40	1095	69.1	14.6	87	21000
06/10/2001	5:06:52	1100	69.1	14.6	85	21000
06/10/2001	5:06:58	1098	69	14.6	86	21000
06/10/2001	5:07:02	1100	68.9	14.6	86	21000
06/10/2001	5:07:08	1100	68.6	14.6	86	21000
06/10/2001	5:07:12	1102	68.5	14.6	84	21000
06/10/2001	5:07:18	1098	68.4	14.6	85	21000
06/10/2001	5:07:22	1097	68.4	14.6	86	21000
06/10/2001	5:07:28	1098	68.1	14.6	86	21000
06/10/2001	5:07:32	1096	68.1	14.6	86	21000
06/10/2001	5:07:38	1101	68.1	14.6	85	21000
06/10/2001	5:07:42	1098	68.1	14.6	86	21000
06/10/2001	5:07:44	1100	68	14.6	85	21000
06/10/2001	5:07:54	1100	68	14.6	85	21000
06/10/2001	5:07:58	1098	68	14.6	86	21000
06/10/2001	5:08:02	1101	67.8	14.6	84	21000
06/10/2001	5:08:08	1100	67.8	14.6	85	21000
06/10/2001	5:08:12	1098	67.8	14.6	86	21000
06/10/2001	5:08:18	1099	67.8	14.6	85	21000
06/10/2001	5:08:22	1100	67.6	14.6	85	21000
06/10/2001	5:08:28	1099	67.6	14.6	85	21000
06/10/2001	5:08:32	1098	67.4	14.6	86	21000

Table D2 – 75% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:08:38	1100	67.4	14.6	85	21000
06/10/2001	5:08:42	1098	67.2	14.6	86	21000
06/10/2001	5:08:48	1099	67.1	14.6	85	21000
06/10/2001	5:08:52	1099	67.1	14.6	85	21000
06/10/2001	5:08:58	1097	67.2	14.6	86	21000
06/10/2001	5:09:02	1099	67.4	14.6	85	21000
06/10/2001	5:09:08	1096	67.6	14.6	86	21000
06/10/2001	5:09:12	1096	67.9	14.6	86	21000
06/10/2001	5:09:18	1102	68.1	14.6	85	21000
06/10/2001	5:09:22	1099	68.2	14.6	86	21000
06/10/2001	5:09:28	1100	68.2	14.6	85	21000
06/10/2001	5:09:32	1099	68.2	14.6	85	21000
06/10/2001	5:09:38	1100	68	14.6	86	21000
06/10/2001	5:09:42	1099	68	14.6	85	21000
06/10/2001	5:09:48	1098	67.9	14.6	85	21000
06/10/2001	5:09:52	1096	67.9	14.6	87	21000
06/10/2001	5:09:58	1100	67.9	14.6	85	21000
06/10/2001	5:10:02	1101	68	14.6	85	21000
06/10/2001	5:10:08	1099	68.2	14.6	85	21000
06/10/2001	5:10:12	1098	68.4	14.6	85	21000
06/10/2001	5:10:18	1099	68.6	14.6	85	21000
06/10/2001	5:10:22	1098	68.6	14.6	86	21000
06/10/2001	5:10:22	1098	68.6	14.6	86	21000
06/10/2001	5:10:32	1098	68.4	14.6	86	21000
06/10/2001	5:10:38	1099	68	14.6	85	21000
06/10/2001	5:10:40	1099	67.9	14.6	85	21000
06/10/2001	5:10:40	1099	67.9	14.6	85	21000
06/10/2001	5:10:52	1099	67.6	14.6	85	21000
06/10/2001	5:10:58	1098	67.5	14.6	86	21000
06/10/2001	5:11:02	1099	67.2	14.6	85	21000
06/10/2001	5:11:08	1098	66.9	14.6	85	21000
06/10/2001	5:11:12	1098	66.6	14.6	86	21000
06/10/2001	5:11:18	1101	66.4	14.6	85	21000
06/10/2001	5:11:22	1099	66.2	14.6	84	21000
06/10/2001	5:11:22	1099	66.2	14.6	84	21000
06/10/2001	5:11:32	1095	66	14.6	85	21000
06/10/2001	5:11:34	1097	66	14.6	86	21000

Table D2 – 75% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:11:34	1097	66	14.6	86	21000
06/10/2001	5:11:48	1099	65.8	14.6	85	21000
06/10/2001	5:11:52	1099	65.6	14.6	84	21000
06/10/2001	5:11:58	1100	65.5	14.6	84	21000
06/10/2001	5:12:02	1098	65.4	14.6	85	21000
06/10/2001	5:12:08	1099	65.1	14.6	84	21000
06/10/2001	5:12:12	1099	65.1	14.6	84	21000
06/10/2001	5:12:18	1098	65.2	14.6	85	21000
06/10/2001	5:12:22	1098	65.2	14.6	85	21000
06/10/2001	5:12:28	1098	65.4	14.6	84	21000
06/10/2001	5:12:32	1098	65.6	14.6	86	21000
06/10/2001	5:12:38	1102	66	14.6	84	21000
06/10/2001	5:12:42	1097	66.1	14.6	85	21000
06/10/2001	5:12:48	1099	66.2	14.6	85	21000
06/10/2001	5:12:52	1097	66.2	14.6	85	21000
06/10/2001	5:12:58	1098	66.5	14.6	85	21000
06/10/2001	5:13:02	1098	66.6	14.6	85	21000
06/10/2001	5:13:08	1100	66.8	14.6	84	21000
06/10/2001	5:13:12	1100	66.8	14.6	85	21000
06/10/2001	5:13:18	1102	66.6	14.6	84	21000
06/10/2001	5:13:22	1098	66.5	14.6	85	21000
06/10/2001	5:13:28	1100	66.2	14.6	85	21000
06/10/2001	5:13:32	1101	66.1	14.6	84	21000
06/10/2001	5:13:36	1098	65.8	14.6	86	21000
06/10/2001	5:13:36	1098	65.8	14.6	86	21000
06/10/2001	5:13:48	1097	65.4	14.6	85	21000
06/10/2001	5:13:52	1099	65.5	14.6	85	21000
06/10/2001	5:13:56	1101	65.6	14.6	85	21000
06/10/2001	5:13:56	1101	65.6	14.6	85	21000
06/10/2001	5:14:06	1100	65.6	14.6	85	21000
06/10/2001	5:14:06	1100	65.6	14.6	85	21000
06/10/2001	5:14:16	1102	65.8	14.6	84	21000
06/10/2001	5:14:16	1102	65.8	14.6	84	21000
06/10/2001	5:14:28	1096	65.9	14.6	85	21000
06/10/2001	5:14:32	1099	66.1	14.6	85	21000
06/10/2001	5:14:32	1099	66.1	14.6	85	21000
06/10/2001	5:14:42	1100	66.4	14.6	84	21000

Table D2 – 75% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:14:48	1097	66.5	14.6	85	21000
06/10/2001	5:14:52	1098	66.6	14.6	85	21000
06/10/2001	5:14:58	1097	66.6	14.6	85	21000
06/10/2001	5:15:04	1103	66.6	14.6	83	21000
06/10/2001	5:15:08	1097	66.6	14.6	85	21000
06/10/2001	5:15:12	1101	66.6	14.6	85	21000
06/10/2001	5:15:18	1100	66.8	14.6	84	21000
06/10/2001	5:15:22	1098	66.6	14.6	86	21000
06/10/2001	5:15:26	1097	66.6	14.6	85	21000
06/10/2001	5:15:26	1097	66.6	14.6	85	21000
06/10/2001	5:15:38	1098	66.5	14.6	85	21000
06/10/2001	5:15:42	1100	66.5	14.6	84	21000
06/10/2001	5:15:48	1098	66.4	14.6	85	21000
06/10/2001	5:15:52	1101	66.4	14.6	84	21000
06/10/2001	5:15:58	1098	66.4	14.6	85	21000
06/10/2001	5:16:02	1100	66.4	14.6	85	21000
06/10/2001	5:16:08	1102	66.4	14.6	84	21000
06/10/2001	5:16:12	1099	66.5	14.6	85	21000
06/10/2001	5:16:18	1098	66.5	14.6	85	21000
06/10/2001	5:16:24	1101	66.5	14.6	84	21000
06/10/2001	5:16:28	1099	66.4	14.6	85	21000
06/10/2001	5:16:32	1098	66.4	14.6	85	21000
06/10/2001	5:16:38	1100	66.2	14.6	84	21000
06/10/2001	5:16:42	1100	66.2	14.6	84	21000
06/10/2001	5:16:48	1095	66.2	14.6	87	21000
06/10/2001	5:16:52	1101	66.1	14.6	85	21000
06/10/2001	5:16:58	1102	66.1	14.6	84	21000
06/10/2001	5:17:04	1099	66	14.6	84	21000
06/10/2001	5:17:08	1100	65.9	14.6	84	21000
06/10/2001	5:17:12	1098	65.9	14.6	85	21000
06/10/2001	5:17:18	1101	65.9	14.6	84	21000
06/10/2001	5:17:22	1098	66	14.6	85	21000
06/10/2001	5:17:28	1098	66	14.6	84	21000
06/10/2001	5:17:32	1097	66	14.6	85	21000
06/10/2001	5:17:38	1100	66	14.6	85	21000
06/10/2001	5:17:42	1098	66	14.6	84	21000
06/10/2001	5:17:46	1098	66.1	14.6	85	21000

Table D2 – 75% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:17:46	1098	66.1	14.6	85	21000
06/10/2001	5:17:56	1099	66.4	14.6	85	21000
06/10/2001	5:17:56	1099	66.4	14.6	85	21000
06/10/2001	5:17:56	1099	66.4	14.6	85	21000
06/10/2001	5:17:56	1099	66.4	14.6	85	21000
06/10/2001	5:18:18	1098	66	14.6	86	21000
06/10/2001	5:18:24	1099	66.1	14.6	85	21000
06/10/2001	5:18:24	1101	66.1	14.6	84	21000
06/10/2001	5:18:24	1101	66.1	14.6	84	21000
06/10/2001	5:18:38	1097	65.8	14.6	85	21000
06/10/2001	5:18:42	1099	65.6	14.6	84	21000
06/10/2001	5:18:48	1100	65.5	14.6	84	21000
06/10/2001	5:18:54	1100	65.4	14.6	85	21000
06/10/2001	5:18:58	1099	65.5	14.6	85	21000
06/10/2001	5:19:02	1100	65.5	14.6	84	21000
06/10/2001	5:19:08	1100	65.6	14.6	84	21000
06/10/2001	5:19:12	1098	65.6	14.6	85	21000
06/10/2001	5:19:18	1100	65.8	14.6	85	21000
06/10/2001	5:19:22	1101	66	14.6	84	21000
06/10/2001	5:19:28	1098	66.2	14.6	85	21000
06/10/2001	5:19:32	1099	66.4	14.6	84	21000
06/10/2001	5:19:38	1102	66.5	14.6	84	21000
06/10/2001	5:19:42	1098	66.5	14.6	85	21000
06/10/2001	5:19:48	1103	66.6	14.6	83	21000
06/10/2001	5:19:52	1099	66.6	14.6	84	21000
06/10/2001	5:19:58	1097	66.6	14.6	85	21000
06/10/2001	5:19:58	1097	66.6	14.6	85	21000
06/10/2001	5:20:08	1099	66.5	14.6	85	21000
06/10/2001	5:20:12	1099	66.2	14.6	85	21000
06/10/2001	5:20:18	1100	66	14.6	85	21000
06/10/2001	5:20:22	1099	65.9	14.6	84	21000
06/10/2001	5:20:28	1098	65.8	14.6	85	21000
06/10/2001	5:20:30	1101	65.6	14.6	84	21000
06/10/2001	5:20:30	1101	65.6	14.6	84	21000
06/10/2001	5:20:42	1098	65.2	14.6	85	21000
06/10/2001	5:20:48	1100	65.2	14.6	85	21000
06/10/2001	5:20:52	1103	65	14.6	84	21000

Table D2 – 75% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:20:56	1096	65.2	14.6	85	21000
06/10/2001	5:20:56	1096	65.2	14.6	85	21000
06/10/2001	5:21:08	1099	65.5	14.6	85	21000
06/10/2001	5:21:12	1101	65.8	14.6	85	21000
06/10/2001	5:21:18	1102	65.9	14.6	83	21000
06/10/2001	5:21:22	1099	66.1	14.6	85	21000
06/10/2001	5:21:28	1100	66.2	14.6	84	21000
06/10/2001	5:21:34	1099	66.4	14.6	85	21000
06/10/2001	5:21:38	1097	66.4	14.6	85	21000
06/10/2001	5:21:42	1100	66.2	14.6	84	21000
06/10/2001	5:21:48	1098	66.1	14.6	85	21000
06/10/2001	5:21:52	1099	65.9	14.6	85	21000
06/10/2001	5:21:58	1100	65.8	14.6	85	21000
06/10/2001	5:22:02	1098	65.6	14.6	85	21000
06/10/2001	5:22:08	1098	65.4	14.6	85	21000
06/10/2001	5:22:12	1100	65.4	14.6	85	21000
06/10/2001	5:22:18	1099	65.4	14.6	85	21000
06/10/2001	5:22:22	1098	65.4	14.6	86	21000
06/10/2001	5:22:28	1100	65.5	14.6	84	21000
06/10/2001	5:22:32	1098	65.6	14.6	85	21000
06/10/2001	5:22:38	1098	65.8	14.6	85	21000
06/10/2001	5:22:42	1100	65.8	14.6	85	21000
06/10/2001	5:22:48	1101	66.1	14.6	84	21000
06/10/2001	5:22:52	1098	66.4	14.6	85	21000
06/10/2001	5:22:58	1098	66.5	14.6	85	21000
06/10/2001	5:23:02	1099	66.6	14.6	85	21000
06/10/2001	5:23:08	1099	66.6	14.6	84	21000
06/10/2001	5:23:12	1098	66.6	14.6	85	21000
06/10/2001	5:23:18	1098	66.6	14.6	86	21000
06/10/2001	5:23:22	1102	66.5	14.6	83	21000
06/10/2001	5:23:28	1101	66.2	14.6	84	21000
06/10/2001	5:23:32	1098	66.1	14.6	85	21000
06/10/2001	5:23:38	1099	66.1	14.6	85	21000
06/10/2001	5:23:42	1101	66	14.6	83	21000
06/10/2001	5:23:46	1097	66	14.6	85	21000
06/10/2001	5:23:46	1097	66	14.6	85	21000
06/10/2001	5:23:58	1104	65.8	14.6	83	21000

Table D2 – 75% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:24:02	1099	65.9	14.6	84	21000
06/10/2001	5:24:08	1098	66	14.6	84	21000
06/10/2001	5:24:12	1099	65.9	14.6	84	21000
06/10/2001	5:24:18	1097	66.1	14.6	86	21000
06/10/2001	5:24:18	1097	66.1	14.6	86	21000
06/10/2001	5:24:28	1101	66	14.6	84	21000
06/10/2001	5:24:32	1098	65.9	14.6	85	21000
06/10/2001	5:24:38	1097	65.6	14.6	85	21000
06/10/2001	5:24:42	1098	65.5	14.6	85	21000
06/10/2001	5:24:44	1099	65.6	14.6	85	21000
06/10/2001	5:24:44	1099	65.6	14.6	85	21000
06/10/2001	5:24:58	1098	65.2	14.6	85	21000
06/10/2001	5:25:02	1098	65.4	14.6	84	21000
06/10/2001	5:25:08	1099	65.6	14.6	84	21000
06/10/2001	5:25:12	1097	65.9	14.6	85	21000
06/10/2001	5:25:18	1101	66.1	14.6	83	21000
06/10/2001	5:25:22	1095	66.4	14.6	85	21000
06/10/2001	5:25:28	1101	66.8	14.6	84	21000
06/10/2001	5:25:32	1098	66.9	14.6	85	21000
06/10/2001	5:25:38	1100	67	14.6	84	21000
06/10/2001	5:25:42	1099	66.9	14.6	84	21000
06/10/2001	5:25:42	1099	66.9	14.6	84	21000
06/10/2001	5:25:52	1100	66.5	14.6	84	21000
06/10/2001	5:25:58	1097	66.2	14.6	85	21000
06/10/2001	5:26:00	1099	66.1	14.6	85	21000
06/10/2001	5:26:00	1099	66.1	14.6	85	21000
06/10/2001	5:26:12	1099	65.9	14.6	84	21000
06/10/2001	5:26:18	1095	65.8	14.6	86	21000
06/10/2001	5:26:22	1099	65.8	14.6	84	21000
06/10/2001	5:26:22	1099	65.8	14.6	84	21000
06/10/2001	5:26:32	1100	65.9	14.6	85	21000
06/10/2001	5:26:36	1097	66	14.6	86	21000
06/10/2001	5:26:36	1097	66	14.6	86	21000
06/10/2001	5:26:48	1100	66.5	14.6	85	21000
06/10/2001	5:26:52	1100	66.8	14.6	84	21000
06/10/2001	5:26:58	1097	67	14.6	85	21000
06/10/2001	5:27:02	1099	66.9	14.6	85	21000

Table D2 – 75% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:27:08	1102	67	14.6	84	21000
06/10/2001	5:27:12	1098	67.1	14.6	85	21000
06/10/2001	5:27:18	1100	67.1	14.6	84	21000
06/10/2001	5:27:22	1099	67.1	14.6	84	21000
06/10/2001	5:27:28	1100	67.1	14.6	84	21000
06/10/2001	5:27:32	1098	66.9	14.6	85	21000
06/10/2001	5:27:38	1099	66.5	14.6	85	21000
06/10/2001	5:27:42	1099	66.4	14.6	85	21000
06/10/2001	5:27:48	1099	66.1	14.6	85	21000
06/10/2001	5:27:50	1099	66.1	14.6	85	21000
06/10/2001	5:28:02	1099	66	14.6	84	21000
06/10/2001	5:28:08	1101	65.9	14.6	84	21000
06/10/2001	5:28:12	1099	65.9	14.6	85	21000
06/10/2001	5:28:18	1100	66.1	14.6	85	21000
06/10/2001	5:28:22	1099	66.1	14.6	85	21000
06/10/2001	5:28:28	1098	66.2	14.6	85	21000
06/10/2001	5:28:32	1100	66.2	14.6	84	21000
06/10/2001	5:28:38	1098	66	14.6	85	21000
06/10/2001	5:28:42	1097	65.9	14.6	85	21000
06/10/2001	5:28:48	1101	65.8	14.6	85	21000
06/10/2001	5:28:52	1099	65.6	14.6	84	21000
06/10/2001	5:28:54	1097	65.8	14.6	85	21000
06/10/2001	5:28:54	1097	65.8	14.6	85	21000
06/10/2001	5:29:08	1100	66.1	14.6	84	21000
06/10/2001	5:29:12	1100	66.1	14.6	84	21000
06/10/2001	5:29:18	1098	66.1	14.6	85	21000
06/10/2001	5:29:22	1098	66.1	14.6	86	21000
06/10/2001	5:29:28	1099	66	14.6	85	21000
06/10/2001	5:29:32	1098	66	14.6	85	21000
06/10/2001	5:29:38	1102	66	14.6	83	21000
06/10/2001	5:29:38	1102	66	14.6	83	21000
06/10/2001	5:29:48	1101	66	14.6	85	21000
06/10/2001	5:29:52	1100	65.9	14.6	84	21000
06/10/2001	5:29:58	1099	65.9	14.6	85	21000
06/10/2001	5:30:02	1101	65.8	14.6	85	21000
06/10/2001	5:30:08	1100	65.6	14.6	84	21000
06/10/2001	5:30:12	1096	65.6	14.6	84	21000

Table D2 – 75% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:30:18	1098	65.5	14.6	84	21000
06/10/2001	5:30:22	1098	65.4	14.6	85	21000
06/10/2001	5:30:28	1097	65	14.6	85	21000
06/10/2001	5:30:32	1101	64.8	14.6	83	21000
06/10/2001	5:30:38	1098	64.6	14.6	84	21000
06/10/2001	5:30:42	1099	64.5	14.6	85	21000
06/10/2001	5:30:48	1099	64.5	14.6	85	21000
06/10/2001	5:30:54	1100	64.6	14.6	85	21000
06/10/2001	5:30:58	1098	64.5	14.6	85	21000
06/10/2001	5:31:02	1099	64.8	14.6	84	21000
06/10/2001	5:31:08	1099	64.8	14.6	85	21000
06/10/2001	5:31:10	1098	64.9	14.6	85	21000
06/10/2001	5:31:18	1101	65	14.6	84	21000
06/10/2001	5:31:22	1096	65	14.6	86	21000
06/10/2001	5:31:28	1101	65	14.6	85	21000
06/10/2001	5:31:32	1098	65.2	14.6	84	21000
06/10/2001	5:31:38	1099	65.4	14.6	84	21000
06/10/2001	5:31:40	1098	65.4	14.6	84	21000
06/10/2001	5:31:40	1098	65.4	14.6	84	21000
06/10/2001	5:31:52	1100	65.5	14.6	84	21000
06/10/2001	5:31:58	1099	65.4	14.6	85	21000
06/10/2001	5:32:02	1100	65.4	14.6	84	21000
06/10/2001	5:32:08	1100	64.9	14.6	84	21000
06/10/2001	5:32:12	1102	64.9	14.6	84	21000
06/10/2001	5:32:18	1097	64.8	14.6	85	21000

Table D3 – 50% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:32:22	1118	64.8	14.6	72	14000
06/10/2001	5:32:28	1134	64.9	14.6	70	14000
06/10/2001	5:32:32	1109	65.2	14.6	60	14000
06/10/2001	5:32:38	1109	65.6	14.6	61	14000
06/10/2001	5:32:42	1111	65.9	14.6	59	14000
06/10/2001	5:32:48	1106	66.2	14.6	60	14000
06/10/2001	5:32:52	1106	66.5	14.6	62	14000
06/10/2001	5:32:58	1111	66.9	14.6	60	14000
06/10/2001	5:33:02	1109	67.1	14.6	61	14000
06/10/2001	5:33:08	1109	67.5	14.6	60	14000
06/10/2001	5:33:08	1109	67.5	14.6	60	14000
06/10/2001	5:33:08	1109	67.5	14.6	60	14000
06/10/2001	5:33:08	1109	67.5	14.6	60	14000
06/10/2001	5:33:28	1112	68	14.6	59	14000
06/10/2001	5:33:32	1111	68.1	14.6	60	14000
06/10/2001	5:33:38	1111	68.2	14.6	59	14000
06/10/2001	5:33:42	1108	68.2	14.6	61	14000
06/10/2001	5:33:48	1113	68.1	14.6	59	14000
06/10/2001	5:33:52	1111	68.1	14.6	59	14000
06/10/2001	5:33:58	1111	68	14.6	61	14000
06/10/2001	5:34:02	1112	68	14.6	60	14000
06/10/2001	5:34:08	1112	68	14.6	60	14000
06/10/2001	5:34:12	1110	68.1	14.6	60	14000
06/10/2001	5:34:18	1113	68.2	14.6	58	14000
06/10/2001	5:34:22	1110	68.2	14.6	59	14000
06/10/2001	5:34:28	1109	68.2	14.6	60	14000
06/10/2001	5:34:32	1110	68.2	14.6	61	14000
06/10/2001	5:34:38	1111	68.2	14.6	60	14000
06/10/2001	5:34:42	1109	68.2	14.6	60	14000
06/10/2001	5:34:46	1112	68.2	14.6	59	14000
06/10/2001	5:34:46	1112	68.2	14.6	59	14000
06/10/2001	5:34:58	1109	68.4	14.6	61	14000
06/10/2001	5:35:02	1116	68.2	14.6	58	14000
06/10/2001	5:35:08	1109	68.1	14.6	60	14000
06/10/2001	5:35:12	1110	67.9	14.6	60	14000
06/10/2001	5:35:18	1110	67.8	14.6	59	14000
06/10/2001	5:35:22	1109	67.6	14.6	60	14000

Table D3 – 50% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In.Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:35:28	1111	67.6	14.6	60	14000
06/10/2001	5:35:32	1111	67.5	14.6	59	14000
06/10/2001	5:35:38	1112	67.4	14.6	59	14000
06/10/2001	5:35:42	1110	67.2	14.6	60	14000
06/10/2001	5:35:48	1114	67.2	14.6	59	14000
06/10/2001	5:35:52	1109	67.2	14.6	60	14000
06/10/2001	5:35:58	1112	67.4	14.6	60	14000
06/10/2001	5:36:02	1111	67.2	14.6	60	14000
06/10/2001	5:36:08	1112	67.2	14.6	60	14000
06/10/2001	5:36:12	1112	67.1	14.6	59	14000
06/10/2001	5:36:14	1112	67.1	14.6	59	14000
06/10/2001	5:36:14	1112	67.1	14.6	59	14000
06/10/2001	5:36:28	1111	66.9	14.6	59	14000
06/10/2001	5:36:32	1108	66.9	14.6	60	14000
06/10/2001	5:36:38	1111	66.9	14.6	59	14000
06/10/2001	5:36:42	1113	67	14.6	58	14000
06/10/2001	5:36:48	1112	67	14.6	60	14000
06/10/2001	5:36:52	1113	67	14.6	59	14000
06/10/2001	5:36:58	1110	67.1	14.6	59	14000
06/10/2001	5:37:02	1110	67.1	14.6	59	14000
06/10/2001	5:37:08	1113	67.1	14.6	58	14000
06/10/2001	5:37:12	1110	67.1	14.6	59	14000
06/10/2001	5:37:14	1113	67.1	14.6	58	14000
06/10/2001	5:37:24	1113	67.1	14.6	58	14000
06/10/2001	5:37:28	1110	66.8	14.6	60	14000
06/10/2001	5:37:30	1111	66.6	14.6	60	14000
06/10/2001	5:37:38	1112	66.5	14.6	59	14000
06/10/2001	5:37:42	1112	66.4	14.6	59	14000
06/10/2001	5:37:48	1109	66.5	14.6	61	14000
06/10/2001	5:37:48	1109	66.5	14.6	61	14000
06/10/2001	5:37:58	1112	66.5	14.6	59	14000
06/10/2001	5:38:04	1116	66.5	14.6	58	14000
06/10/2001	5:38:08	1107	66.4	14.6	60	14000
06/10/2001	5:38:08	1107	66.4	14.6	60	14000
06/10/2001	5:38:18	1112	66.4	14.6	59	14000
06/10/2001	5:38:22	1112	66.4	14.6	59	14000
06/10/2001	5:38:28	1112	66.2	14.6	58	14000

Table D3 – 50% Power Load Page 2

Table D3 – 50% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:38:32	1112	66.2	14.6	59	14000
06/10/2001	5:38:38	1112	66.1	14.6	59	14000
06/10/2001	5:38:42	1111	66	14.6	58	14000
06/10/2001	5:38:48	1110	66	14.6	61	14000
06/10/2001	5:38:50	1114	65.9	14.6	59	14000
06/10/2001	5:38:50	1114	65.9	14.6	59	14000
06/10/2001	5:39:02	1113	65.9	14.6	59	14000
06/10/2001	5:39:08	1114	65.8	14.6	59	14000
06/10/2001	5:39:12	1113	65.6	14.6	58	14000
06/10/2001	5:39:12	1113	65.6	14.6	58	14000
06/10/2001	5:39:22	1110	65.5	14.6	59	14000
06/10/2001	5:39:22	1110	65.5	14.6	59	14000
06/10/2001	5:39:32	1113	65.1	14.6	59	14000
06/10/2001	5:39:38	1112	64.8	14.6	60	14000
06/10/2001	5:39:42	1114	64.6	14.6	58	14000
06/10/2001	5:39:48	1113	64.4	14.6	59	14000
06/10/2001	5:39:52	1111	64.2	14.6	59	14000
06/10/2001	5:39:58	1112	64.1	14.6	60	14000
06/10/2001	5:40:02	1110	64.4	14.6	60	14000
06/10/2001	5:40:08	1117	65	14.6	58	14000
06/10/2001	5:40:12	1107	65.2	14.6	61	14000
06/10/2001	5:40:18	1109	65.5	14.6	60	14000
06/10/2001	5:40:22	1111	65.5	14.6	60	14000
06/10/2001	5:40:28	1113	65.5	14.6	59	14000
06/10/2001	5:40:32	1109	65.5	14.6	60	14000
06/10/2001	5:40:34	1110	65.5	14.6	61	14000
06/10/2001	5:40:34	1110	65.5	14.6	61	14000
06/10/2001	5:40:44	1114	65.5	14.6	59	14000
06/10/2001	5:40:44	1114	65.5	14.6	59	14000
06/10/2001	5:40:58	1109	65.5	14.6	59	14000
06/10/2001	5:41:02	1116	65.2	14.6	58	14000
06/10/2001	5:41:02	1116	65.2	14.6	58	14000
06/10/2001	5:41:12	1114	64.9	14.6	58	14000
06/10/2001	5:41:18	1111	64.6	14.6	59	14000
06/10/2001	5:41:22	1112	64.6	14.6	59	14000
06/10/2001	5:41:28	1110	64.6	14.6	59	14000
06/10/2001	5:41:32	1115	64.5	14.6	59	14000

Table D3 – 50% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:41:38	1112	64.5	14.6	59	14000
06/10/2001	5:41:42	1112	64.5	14.6	58	14000
06/10/2001	5:41:48	1112	64.2	14.6	59	14000
06/10/2001	5:41:52	1112	64.1	14.6	59	14000
06/10/2001	5:41:58	1112	64	14.6	59	14000
06/10/2001	5:42:02	1111	63.9	14.6	59	14000
06/10/2001	5:42:08	1109	63.9	14.6	60	14000
06/10/2001	5:42:12	1111	64	14.6	60	14000
06/10/2001	5:42:18	1113	63.9	14.6	59	14000
06/10/2001	5:42:22	1112	63.9	14.6	58	14000
06/10/2001	5:42:28	1113	64	14.6	58	14000
06/10/2001	5:42:32	1110	64.1	14.6	60	14000
06/10/2001	5:42:38	1111	64.1	14.6	59	14000
06/10/2001	5:42:42	1110	64.1	14.6	59	14000
06/10/2001	5:42:48	1109	64	14.6	60	14000
06/10/2001	5:42:52	1115	64	14.6	58	14000
06/10/2001	5:42:56	1110	64	14.6	59	14000
06/10/2001	5:42:56	1110	64	14.6	59	14000
06/10/2001	5:43:08	1114	64	14.6	58	14000
06/10/2001	5:43:12	1112	64	14.6	59	14000
06/10/2001	5:43:18	1111	64.1	14.6	60	14000
06/10/2001	5:43:20	1113	64	14.6	59	14000
06/10/2001	5:43:20	1113	64	14.6	59	14000
06/10/2001	5:43:20	1113	64	14.6	59	14000
06/10/2001	5:43:38	1111	63.9	14.6	59	14000
06/10/2001	5:43:42	1111	64	14.6	60	14000
06/10/2001	5:43:48	1110	64	14.6	60	14000
06/10/2001	5:43:54	1110	64	14.6	59	14000
06/10/2001	5:43:58	1116	64	14.6	59	14000
06/10/2001	5:44:02	1113	64.2	14.6	59	14000
06/10/2001	5:44:08	1111	64.4	14.6	60	14000
06/10/2001	5:44:12	1112	64.6	14.6	59	14000
06/10/2001	5:44:18	1112	65	14.6	59	14000
06/10/2001	5:44:22	1112	65.1	14.6	59	14000
06/10/2001	5:44:28	1112	65.1	14.6	59	14000
06/10/2001	5:44:32	1113	65	14.6	58	14000
06/10/2001	5:44:38	1110	64.5	14.6	59	14000

Table D3 – 50% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:44:42	1114	64.4	14.6	58	14000
06/10/2001	5:44:48	1111	64.1	14.6	59	14000
06/10/2001	5:44:52	1114	64	14.6	59	14000
06/10/2001	5:44:58	1113	63.9	14.6	59	14000
06/10/2001	5:45:02	1114	63.9	14.6	59	14000
06/10/2001	5:45:08	1112	63.9	14.6	59	14000
06/10/2001	5:45:12	1111	64	14.6	59	14000
06/10/2001	5:45:18	1109	64	14.6	59	14000
06/10/2001	5:45:22	1111	64	14.6	59	14000
06/10/2001	5:45:28	1111	64.2	14.6	60	14000
06/10/2001	5:45:32	1116	64.4	14.6	58	14000
06/10/2001	5:45:36	1111	64.6	14.6	59	14000
06/10/2001	5:45:42	1113	65	14.6	58	14000
06/10/2001	5:45:48	1112	65.2	14.6	58	14000
06/10/2001	5:45:52	1110	65.4	14.6	60	14000
06/10/2001	5:45:58	1111	65.5	14.6	59	14000
06/10/2001	5:46:02	1110	65.6	14.6	59	14000
06/10/2001	5:46:08	1113	65.6	14.6	59	14000
06/10/2001	5:46:12	1112	65.8	14.6	59	14000
06/10/2001	5:46:18	1112	65.8	14.6	59	14000
06/10/2001	5:46:22	1109	65.8	14.6	60	14000
06/10/2001	5:46:28	1112	65.9	14.6	59	14000
06/10/2001	5:46:32	1113	66	14.6	58	14000
06/10/2001	5:46:38	1110	66	14.6	59	14000
06/10/2001	5:46:42	1110	66	14.6	59	14000
06/10/2001	5:46:48	1110	66	14.6	59	14000
06/10/2001	5:46:52	1112	66	14.6	59	14000
06/10/2001	5:46:58	1110	65.9	14.6	59	14000
06/10/2001	5:47:02	1113	65.8	14.6	60	14000
06/10/2001	5:47:08	1113	65.5	14.6	58	14000
06/10/2001	5:47:12	1111	65.1	14.6	59	14000
06/10/2001	5:47:18	1110	65	14.6	60	14000
06/10/2001	5:47:22	1115	65	14.6	57	14000
06/10/2001	5:47:28	1112	65.1	14.6	59	14000
06/10/2001	5:47:32	1109	65.1	14.6	60	14000
06/10/2001	5:47:38	1116	65.1	14.6	58	14000
06/10/2001	5:47:42	1112	65.1	14.6	58	14000

Table D3 – 50% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:47:46	1109	65.2	14.6	59	14000
06/10/2001	5:47:46	1109	65.2	14.6	59	14000
06/10/2001	5:47:46	1109	65.2	14.6	59	14000
06/10/2001	5:47:46	1109	65.2	14.6	59	14000
06/10/2001	5:48:08	1110	64.5	14.6	59	14000
06/10/2001	5:48:12	1113	64.2	14.6	58	14000
06/10/2001	5:48:18	1110	64.1	14.6	60	14000
06/10/2001	5:48:22	1110	64.1	14.6	60	14000
06/10/2001	5:48:26	1113	64.1	14.6	59	14000
06/10/2001	5:48:26	1113	64.1	14.6	59	14000
06/10/2001	5:48:38	1112	64	14.6	58	14000
06/10/2001	5:48:42	1109	64	14.6	59	14000
06/10/2001	5:48:48	1113	64	14.6	59	14000
06/10/2001	5:48:50	1109	64	14.6	60	14000
06/10/2001	5:48:58	1110	64	14.6	60	14000
06/10/2001	5:49:02	1110	64.1	14.6	59	14000
06/10/2001	5:49:08	1113	64	14.6	58	14000
06/10/2001	5:49:12	1116	64	14.6	58	14000
06/10/2001	5:49:18	1109	64	14.6	60	14000
06/10/2001	5:49:22	1115	64	14.6	58	14000
06/10/2001	5:49:28	1111	64	14.6	59	14000
06/10/2001	5:49:34	1114	64	14.6	58	14000
06/10/2001	5:49:38	1109	64.1	14.6	60	14000
06/10/2001	5:49:42	1114	64	14.6	59	14000
06/10/2001	5:49:48	1111	64	14.6	59	14000
06/10/2001	5:49:52	1110	64	14.6	59	14000
06/10/2001	5:49:58	1114	64	14.6	59	14000
06/10/2001	5:49:58	1114	64	14.6	59	14000
06/10/2001	5:50:08	1112	64	14.6	59	14000
06/10/2001	5:50:12	1114	64	14.6	59	14000
06/10/2001	5:50:18	1114	64	14.6	58	14000
06/10/2001	5:50:18	1114	64	14.6	58	14000
06/10/2001	5:50:28	1114	63.9	14.6	58	14000
06/10/2001	5:50:32	1110	64	14.6	59	14000
06/10/2001	5:50:38	1112	63.9	14.6	59	14000
06/10/2001	5:50:42	1113	63.9	14.6	59	14000
06/10/2001	5:50:42	1113	63.9	14.6	59	14000

Table D3 – 50% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:50:52	1113	63.9	14.6	59	14000
06/10/2001	5:50:58	1111	63.9	14.6	59	14000
06/10/2001	5:51:00	1116	63.9	14.6	57	14000
06/10/2001	5:51:00	1116	63.9	14.6	57	14000
06/10/2001	5:51:12	1110	63.9	14.6	59	14000
06/10/2001	5:51:18	1111	63.9	14.6	59	14000
06/10/2001	5:51:22	1113	64	14.6	58	14000
06/10/2001	5:51:28	1112	64	14.6	59	14000
06/10/2001	5:51:32	1114	64.1	14.6	58	14000
06/10/2001	5:51:32	1114	64.1	14.6	58	14000
06/10/2001	5:51:42	1112	64	14.6	59	14000
06/10/2001	5:51:44	1111	64	14.6	60	14000
06/10/2001	5:51:44	1111	64	14.6	60	14000
06/10/2001	5:51:58	1117	64	14.6	57	14000
06/10/2001	5:52:02	1111	63.9	14.6	59	14000
06/10/2001	5:52:08	1112	64	14.6	59	14000
06/10/2001	5:52:12	1116	64	14.6	58	14000
06/10/2001	5:52:18	1114	64	14.6	59	14000
06/10/2001	5:52:22	1112	64	14.6	59	14000
06/10/2001	5:52:24	1113	64	14.6	59	14000
06/10/2001	5:52:24	1113	64	14.6	59	14000
06/10/2001	5:52:38	1113	64.1	14.6	59	14000
06/10/2001	5:52:42	1112	64.1	14.6	59	14000
06/10/2001	5:52:44	1111	64.1	14.6	59	14000
06/10/2001	5:52:52	1111	64	14.6	59	14000
06/10/2001	5:52:58	1110	63.9	14.6	59	14000
06/10/2001	5:52:58	1110	63.9	14.6	59	14000
06/10/2001	5:53:08	1109	64	14.6	59	14000
06/10/2001	5:53:12	1115	64	14.6	58	14000
06/10/2001	5:53:18	1117	63.9	14.6	57	14000
06/10/2001	5:53:22	1112	63.9	14.6	59	14000
06/10/2001	5:53:28	1111	63.9	14.6	60	14000
06/10/2001	5:53:32	1110	63.9	14.6	60	14000
06/10/2001	5:53:36	1114	64	14.6	58	14000
06/10/2001	5:53:36	1114	64	14.6	58	14000
06/10/2001	5:53:36	1114	64	14.6	58	14000
06/10/2001	5:53:52	1109	64	14.6	59	14000

Table D3 – 50% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:53:58	1113	64	14.6	59	14000
06/10/2001	5:54:02	1113	64	14.6	59	14000
06/10/2001	5:54:08	1110	64	14.6	59	14000
06/10/2001	5:54:12	1113	64	14.6	59	14000
06/10/2001	5:54:12	1113	64	14.6	59	14000
06/10/2001	5:54:22	1117	64.1	14.6	58	14000
06/10/2001	5:54:28	1111	64.1	14.6	60	14000
06/10/2001	5:54:32	1112	64.1	14.6	59	14000
06/10/2001	5:54:38	1113	64.1	14.6	59	14000
06/10/2001	5:54:42	1113	64.2	14.6	58	14000
06/10/2001	5:54:48	1111	64.2	14.6	59	14000
06/10/2001	5:54:52	1110	64.2	14.6	60	14000
06/10/2001	5:54:58	1112	64.2	14.6	59	14000
06/10/2001	5:55:02	1110	64.1	14.6	60	14000
06/10/2001	5:55:08	1115	64.1	14.6	58	14000
06/10/2001	5:55:12	1112	64.1	14.6	59	14000
06/10/2001	5:55:18	1109	64.1	14.6	58	14000
06/10/2001	5:55:22	1106	64.1	14.6	59	14000
06/10/2001	5:55:28	1111	64.1	14.6	59	14000
06/10/2001	5:55:32	1112	64	14.6	59	14000
06/10/2001	5:55:38	1111	64	14.6	59	14000
06/10/2001	5:55:42	1114	64	14.6	58	14000
06/10/2001	5:55:46	1114	64	14.6	58	14000
06/10/2001	5:55:46	1114	64	14.6	58	14000
06/10/2001	5:55:46	1114	64	14.6	58	14000
06/10/2001	5:55:46	1114	64	14.6	58	14000
06/10/2001	5:56:04	1107	64	14.6	60	14000
06/10/2001	5:56:04	1107	64	14.6	60	14000
06/10/2001	5:56:18	1112	64	14.6	59	14000
06/10/2001	5:56:22	1113	64	14.6	59	14000
06/10/2001	5:56:28	1112	64	14.6	58	14000
06/10/2001	5:56:32	1113	64.1	14.6	58	14000
06/10/2001	5:56:38	1114	64.1	14.6	59	14000
06/10/2001	5:56:42	1110	64.1	14.6	61	14000
06/10/2001	5:56:48	1111	64.2	14.6	59	14000
06/10/2001	5:56:52	1112	64.1	14.6	59	14000
06/10/2001	5:56:52	1112	64.1	14.6	59	14000

Table D3 – 50% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	5:57:02	1113	64.5	14.6	58	14000
06/10/2001	5:57:08	1113	64.8	14.6	58	14000
06/10/2001	5:57:12	1110	64.8	14.6	59	14000
06/10/2001	5:57:18	1111	64.6	14.6	60	14000
06/10/2001	5:57:22	1112	64.6	14.6	59	14000
06/10/2001	5:57:28	1113	64.5	14.6	59	14000
06/10/2001	5:57:32	1114	64.5	14.6	59	14000
06/10/2001	5:57:38	1113	64.4	14.6	58	14000
06/10/2001	5:57:42	1114	64.4	14.6	58	14000
06/10/2001	5:57:48	1111	64.4	14.6	59	14000
06/10/2001	5:57:52	1114	64.2	14.6	58	14000
06/10/2001	5:57:58	1110	64.1	14.6	59	14000
06/10/2001	5:58:02	1115	64.1	14.6	57	14000
06/10/2001	5:58:08	1111	64.1	14.6	58	14000
06/10/2001	5:58:08	1111	64.1	14.6	58	14000
06/10/2001	5:58:18	1114	64	14.6	59	14000
06/10/2001	5:58:22	1112	64	14.6	58	14000
06/10/2001	5:58:24	1111	64	14.6	59	14000
06/10/2001	5:58:24	1111	64	14.6	59	14000
06/10/2001	5:58:34	1110	64	14.6	60	14000
06/10/2001	5:58:42	1111	64.1	14.6	59	14000
06/10/2001	5:58:48	1113	64.4	14.6	59	14000
06/10/2001	5:58:52	1110	64.4	14.6	60	14000
06/10/2001	5:58:58	1112	64.4	14.6	60	14000
06/10/2001	5:59:02	1113	64.4	14.6	58	14000
06/10/2001	5:59:08	1110	64	14.6	59	14000
06/10/2001	5:59:12	1113	64	14.6	59	14000
06/10/2001	5:59:18	1112	64	14.6	59	14000
06/10/2001	5:59:22	1112	64	14.6	59	14000
06/10/2001	5:59:28	1114	64	14.6	58	14000
06/10/2001	5:59:32	1110	63.9	14.6	59	14000
06/10/2001	5:59:38	1113	63.9	14.6	58	14000
06/10/2001	5:59:42	1109	63.9	14.6	59	14000
06/10/2001	5:59:48	1111	64	14.6	59	14000
06/10/2001	5:59:52	1113	64	14.6	59	14000
06/10/2001	5:59:58	1112	63.9	14.6	59	14000
06/10/2001	6:00:02	1113	64	14.6	58	14000

Table D3 – 50% Power Load

Control Date	Control Time	Turbine Exit Temp (°F)	Compressor In Temp (°F)	Ambient Pressure (psia)	Fuel Energy Flow BTU/sec	Power Demand (W)
06/10/2001	6:00:08	1116	64	14.6	58	14000
06/10/2001	6:00:12	1111	64	14.6	58	14000
06/10/2001	6:00:18	1111	64	14.6	59	14000
06/10/2001	6:00:22	1114	64	14.6	58	14000
06/10/2001	6:00:26	1114	64.1	14.6	58	14000
06/10/2001	6:00:26	1114	64.1	14.6	58	14000
06/10/2001	6:00:36	1112	64	14.6	59	14000
06/10/2001	6:00:36	1112	64	14.6	59	14000
06/10/2001	6:00:48	1109	63.9	14.6	60	14000
06/10/2001	6:00:52	1116	63.9	14.6	58	14000
06/10/2001	6:00:54	1114	64	14.6	58	14000
06/10/2001	6:00:54	1114	64	14.6	58	14000
06/10/2001	6:01:08	1110	64	14.6	60	14000
06/10/2001	6:01:14	1112	64.1	14.6	59	14000
06/10/2001	6:01:18	1113	64	14.6	58	14000
06/10/2001	6:01:22	1115	64.1	14.6	59	14000
06/10/2001	6:01:28	1113	64.4	14.6	58	14000
06/10/2001	6:01:34	1109	64.5	14.6	58	14000
06/10/2001	6:01:38	1112	64.5	14.6	59	14000
06/10/2001	6:01:42	1115	64.6	14.6	58	14000
06/10/2001	6:01:42	1115	64.6	14.6	58	14000
06/10/2001	6:01:52	1110	64.8	14.6	59	14000
06/10/2001	6:01:58	1113	64.9	14.6	58	14000
06/10/2001	6:02:02	1107	64.8	14.6	61	14000

California Environmental Protection Agency
AIR RESOURCES BOARD

GUIDANCE FOR THE PERMITTING OF ELECTRICAL GENERATION TECHNOLOGIES

Stationary Source Division
Project Assessment Branch

Release Date:
September 2001

State of California
California Environmental Protection Agency
Air Resources Board

Guidance for the Permitting of Electrical Generation Technologies

September 28, 2001

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Appendices

I. EXECUTIVE SUMMARY

A. Introduction

Senate Bill (SB) 1298 (Bowen and Peace), which was chaptered on September 27, 2000, required the Air Resources Board (ARB) to issue guidance to districts on the permitting or certification of electrical generation technologies under the district's regulatory jurisdiction. The statue also directs ARB to adopt a certification program and uniform emission standards for electrical generation technologies that are exempt from air pollution control or air quality management districts' (districts) permitting requirements. The proposed certification program is discussed in the ARB report: Proposed Regulation to Establish a Distributed Generation Certification Program, September 2001.

SB 1298 specifies that the guidelines address Best Available Control Technology (BACT) determinations for electrical generation technologies and, by the earliest practical date, shall make the determinations equivalent to the level determined by the ARB to be BACT for permitted central station power plants in California. Finally, this guidance is to address methods for streamlining the permitting and approval of electrical generation units, including the potential for precertification of one or more types of electrical generation technologies.

This executive summary provides an overview of the development of the Guidelines and a summary of the ARB staff's recommendations.

B. Background

This section briefly discusses the contents of this document in a question-and-answer format. The reader is directed to subsequent chapters for more detailed discussions.

1. What is the purpose of this guidance document?

The purpose of this document is to provide guidance to assist districts in making permitting decisions for electrical generation technologies, particularly generation that is near the place of use (distributed generation (DG)). Applicants will also find this guidance useful when developing and planning a proposed electrical generation project.

2. **How does this guidance differ from the previously issued ARB report: Guidance for Power Plant Siting and Best Available Control Technology?**

The 1999 ARB report entitled Guidance for Power Plant Siting and Best Available Control Technology ("1999 ARB Power Plant Guidance ") provided guidance to the districts on gas turbine electrical generation technologies sized 50 megawatts (MW) or greater. In addition, the 1999 report provided guidance regarding emission offsets, ambient air quality impact analysis, health risk assessment, and other permitting considerations. This new guidance addresses electrical generation technologies not discussed in the ARB Power Plant Guidance (i.e. distributed generation), and in some cases, updates information regarding control technologies. Electrical generation technologies discussed in this guidance include: gas turbines electrical generation technologies sized less than 50 MW using either natural gas or waste gases and stationary reciprocating engines using either fossil fuel or waste gases.

3. **What does this guidance address?**

- Best available control technology (BACT) – the ARB staff's evaluation of recent BACT determinations for gas turbines less than 50 MW and reciprocating engines used in electrical generation; the ARB staff's evaluation of the feasibility of distributed generation technologies achieving emission levels of central station power plants equipped with BACT.

- Other permitting considerations – the ARB staff's evaluation of the air quality benefits of combined heat and power (CHP) electrical generation technologies, and clarification of emissions testing and monitoring requirements.

- Permit Streamlining – the ARB staff's proposed suggestions to streamline the permitting of electrical generation technologies.

4. **How was this guidance developed?**

The ARB's staff proposal was developed in a public process that involved all affected parties. The ARB staff held five public consultation meetings throughout the state during the development of the guidelines to solicit ideas and comments on proposed guideline levels. A DG work group was formed to assist the ARB staff with identifying and resolving issues during the development of the guidelines. The work group, comprised of over 90 representatives of affected industry, environmental groups and district staff, met six times in Sacramento.

The ARB staff also held several conference calls with district staff to obtain the districts' perspectives on the ARB staff's proposed DG program.

C. Recommendations

1. Best Available Control Technology

Health and Safety Code Section 42300 authorizes delegation of stationary source permitting authority from the State to local air districts. Each district has its own set of definitions and rules. As a result, the definition of BACT and, where used, lowest achievable emission rate (LAER) can vary by district.

Federal BACT is defined in Section 169(3) of the federal Clean Air Act. It states that the "term 'best available control technology' means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques,..."

Federal LAER is defined in Section 171(3) of the federal Clean Air Act. It states that the "The term 'lowest achievable emission rate' means for any source, that rate of emissions which reflects --(A) the most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or (B) the most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent."

Most BACT definitions in California are consistent with the federal LAER definition and are often referred to as "California BACT." "California BACT" should not be confused with the less restrictive federal BACT. In the context of this guidance, references to BACT specifically refer to "California BACT."

The ARB staff's recommended BACT emission levels are summarized in Tables I-1 and I-2. These oxides of nitrogen (NOx), volatile organic compounds (VOC), carbon monoxide (CO), and particulate matter (PM) levels are expressed in terms of pounds / megawatt-hour (lb/MW-hr). This convention, which is consistent with the ARB's proposed DG certification program, provides recognition for efficient use of fuels and reduced emissions of greenhouse gases.

Table I-1:
Summary Of BACT For The Control Of Emissions From Stationary Gas Turbines Less Than 50 MW Used In Electrical Generation*

Equipment Category	NOx lb/MW-hr	VOC lb/MW-hr	CO lb/MW-hr	PM lb/MW-hr
< 3 MW	0.5 (9 ppmvd**)	0.1 (5 ppmvd**)	0.4 (10 ppmvd**)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 standard cubic foot
3 - 12 MW	0.25 (5 ppmvd**)	0.04 (2 ppmvd**)	0.2 (6 ppmvd**)	
> 12 and < 50 MW	0.20 (5 ppmvd**)	0.03 (2 ppmvd**)	0.12 (6 ppmvd**)	
Waste gas fired	1.25 (25 ppmvd**)	--	--	--

* all standards based upon 3-hour rolling average and in lb/MW-hr.
** lb/MW-hr standard equivalent to ppmdv value expressed at 15 percent O_2.

Table I-2:
Summary Of BACT For The Control Of Emissions From Reciprocating Engines Used In Electrical Generation

Equipment Category	NOx lb/MW-hr	VOC lb/MW-hr	CO lb/MW-hr	PM lb/MW-hr
Fossil fuel fired	0.5 (0.15 g/bhp-hr or 9 ppmvd*)	0.5 (0.15 g/bhp-hr or 25 ppmvd*)	1.9 (0.6 g/bhp-hr or 56 ppmvd*)	0.06 (0.02 g/bhp-hr)
Waste gas fired	1.9 (0.6 g/bhp-hr or 50 ppmvd*)	1.9 (0.6 g/bhp-hr or 130 ppmvd*)	7.8 (2.5 g/bhp-hr or 300 ppmvd*)	NA

* lb/MW-hr standard is equivalent to g/bhp-hr and ppmdv expressed at 15 percent O_2. Concentration (ppmdv) values are approximate.

The basis for the BACT emission levels in Table I-1 for gas turbines is as follows:

For gas turbines rated at less than 3 MW:

- For NOx, the most stringent emission levels deemed BACT by the South Coast Air Quality Management District;
- For CO, the most stringent emission levels deemed BACT by the South Coast Air Quality Management District; and
- For VOC, the most stringent emission levels deemed BACT by the South Coast Air Quality Management District.

For gas turbines fueled with natural gas rated from 3 MW up to 12 MW:

- For NOx, the most stringent level achieved in practice based upon four annual source tests done at two facilities (three consecutive tests at one facility) and continuous emission monitoring data for each facility;
- For CO, the most stringent level achieved in practice based upon three consecutive annual source tests at one facility and continuous emission monitoring data for this facility; and
- For VOC, the most stringent level achieved in practice based upon three consecutive annual source tests at one facility and continuous emission monitor data for this facility.

The facilities tested are combined cycle applications. In addition, two other facilities under construction, both simple cycle applications, are permitted at these levels.

For gas turbines fueled with natural gas rated from 12 MW up to 50 MW:

- For NOx, the most stringent level achieved in practice based upon ten annual source tests done at four facilities (two consecutive tests at two facilities and three consecutive tests at two facilities) and continuous emission monitoring data for each facility;
- For CO, the most stringent level achieved in practice based upon two consecutive annual source tests at one facility and continuous emission monitoring data for this facility; and
- For VOC, the most stringent level achieved in practice based upon two consecutive annual source tests at one facility and continuous emission monitoring data for this facility.

The facilities tested included a simple cycle and three combined cycle application. In addition, two other facilities under construction, both combined cycle applications, are permitted at these levels.

For gas turbines fueled with waste gas:

- For NOx, the most stringent level achieved in practice based upon three annual source tests at one facility and continuous emission monitoring data for this facility.

The basis for the BACT emission levels in Table I-2 for reciprocating engines is as follows:

For reciprocating engines using fossil fuel:

- For NOx, the most stringent level achieved in practice based upon 35 annual source tests done at 12 facilities and one ARB test (some facilities have been tested four consecutive times);
- For CO, the most stringent level achieved in practice based upon 29 annual source tests done at 12 facilities and one ARB test (some facilities have been tested two consecutive times); and
- For VOC, the most stringent level achieved in practice based upon 25 annual source tests done at 11 facilities and one ARB test (some facilities have been tested two consecutive times).

For waste gas fueled reciprocating engines:

- For NOx, the most stringent level achieved in practice based upon 14 annual source tests done at 9 facilities and continuous emission monitoring data for one facility;
- For CO, the most stringent level achieved in practice based upon 14 annual source tests done at 9 facilities and continuous emission monitoring data for one facility; and
- For VOC, the most stringent level achieved in practice based upon 14 annual source tests done at 9 facilities and continuous emission monitoring data for one facility.

2. Achieving Central Station Power Plant Levels

The ARB staff recommends that, to the extend possible, districts encourage electrical generation projects that are also efficient combined heat and power (CHP) applications and that districts recognize the benefits of CHP and grant credit to electrical generation that are used in efficient CHP applications. The credit would only be used toward satisfying the goal that emissions from electrical generation technologies, at the earliest practicable date, be equivalent to emission levels for central station power plants. Only efficient CHP electrical generation projects are likely to achieve the equivalent emissions of central station power plants equipped with BACT. This can be achieved by requiring electrical generation facilities, after applying the CHP credit, to achieve the equivalent emissions of central station power plants equipped with BACT by 2007.

3. Other Permitting Considerations

Recommendations are provided for addressing health risk assessment requirements, source testing, and emissions monitoring. The ARB staff recommended that districts make permitting decisions consistent with the ARB report: Risk Management Guidelines for New and Modified Sources of Toxics Air Pollutants, July 1993. In the case of diesel-fueled engines, the ARB staff recommends that district's permitting decisions be consistent with the ARB report: Diesel Risk Management Guidelines, October 2000.

The ARB staff provided recommendations for source testing, monitoring of emissions and equipment, and recordkeeping of electric generation technologies. In addition, the ARB staff provided suggested permit conditions based upon these recommendations.

4. Permit Streamlining

The ARB staff recommends that the districts, to the extent reasonable, streamline their permitting programs and procedures for electrical generation. However, the ARB staff recognizes that not all permitting requirements can be streamlined without compromising district requirements. The ARB staff recommends that districts evaluate the following areas in their permitting programs for streamlining opportunities: BACT determinations, precertified emission rates, standardized permit applications, and standardized permit conditions. Finally, the ARB staff encourages districts to adopt standardized permitting thresholds.

II. OVERVIEW

This report provides guidance to local air pollution control districts and air quality management districts (districts) regarding the permitting of electrical generation technologies. In particular, this report describes DG technologies; discusses existing regulations; addresses best available control technology (BACT) determinations; recommended emission levels for oxides of nitrogen (NOx), volatile organic compounds (VOC), carbon monoxide (CO), and particulate matter (PM); discusses how electrical generation technologies can achieve central station power plant levels; other permitting considerations including testing and monitoring requirements and the inclusion of a CHP credit; and methods to streamline the permitting of electrical generation projects under the regulatory jurisdiction of districts.

A. Background

These Guidelines were prepared to satisfy the requirements of Senate Bill (SB) 1298 (Bowen and Peace), which was signed into law September 25, 2000. SB 1298 requires the Air Resources Board (ARB) by January 1, 2003 to: 1) adopt a certification program for electrical generation technologies that are exempt from district permitting requirements; and 2) issue guidance to assist districts on the permitting or certification of electrical generation under their jurisdiction. The certification program is to include emission standards (expressed in pound per megawatt-hour (lb/MW-hr) that reflect the best performance achieved in practice by electrical generation technologies that are exempt from district jurisdiction. In addition, SB 1298 requires the guidance to address BACT determinations for electrical generation technologies. By the earliest practical date, the determinations shall be made equivalent to the level determined by the ARB to be BACT for permitted central station power plants in California; and identify methods for streamlining the permitting and approval of electrical generating units. Appendix A contains a copy of SB 1298.

The 1999 ARB report entitled Guidance for Power Plant Siting and Best Available Control Technology ("1999 ARB Power Plant Guidance ") provided guidance to the districts on gas turbine electrical generation technologies sized 50 megawatts (MW) or greater. This new guidance addresses electrical generation not discussed in the ARB Power Plant Guidance (i.e. distributed generation), and in some cases, updates information regarding control technologies.

B. What Is Distributed Generation?

SB 1298 defines distributed generation (DG) as electric generation located near the place of use. A variety of technologies can be used for DG, including photovoltaics, wind turbines, fuel cells, reciprocating engines (external and internal combustion), and gas turbines. Although reciprocating engines and gas turbines can use a variety of gaseous and liquid fuels, most commonly they use natural gas and diesel.

Some DG technologies can be used in combined heat and power (CHP) applications. CHP applications produce both electric power and process heat from the combustion/processing of the same fuel. CHP applications have increased energy efficiency (total useful energy output / energy input) and decreased production of greenhouse gases. Fuel cells, reciprocating engines, and gas turbines have been used as CHP applications.

C. Key Terms

Attainment Areas - an area with ambient air quality, demonstrated by a monitoring program, to be below the ambient air quality standard promulgated by the Air Resources Board or the United States Environmental Protection Agency.

Best Available Control Technology (BACT) - air pollution control technology requirement from district new source review programs. In California, many air pollution control agencies use the term BACT to refer to Lowest Achievable Emissions Rate (LAER). LAER is the emissions control level required of a source seeking a permit in a nonattainment area. LAER is generally considered to be the most stringent level of control required under the federal Clean Air Act.

Best Available Retrofit Control Technology (BARCT) - defined in the California Health and Safety Code, section 40406, but applicable statewide in this case, as "an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source."

Central Station Power Plant Equipped with BACT - combined cycle gas turbine electrical generation equipped with selective catalytic reduction and oxidation catalyst and achieves 0.06 lb/MW-hr for NOx, 0.02 lb/MW-hr for VOC, and 0.09 lb/MW-hr for CO. If line losses are included, then the emissions are 0.07 lb/MW-hr for NOx, 0.02 lb/MW-hr for VOC, and 0.1 lb/MW-hr for CO.

Combined Heat and Power - applications that produce both electric power and process heat from the combustion/processing of the same fuel. Process heat refers to the thermal energy used such as hot water heated and consumed by occupants at a building and not the potential thermal energy produced by the unit.

Continuous Emission Monitor (CEM) - equipment that continuously measures the emissions of criteria pollutants. Equipment must be periodically calibrated to ensure accuracy of measurements.

Distributed Generation - electrical generation located near the place of use.

Emergency - when electrical or natural gas service fails or emergency pumping of water for fire protection or flood relief is required.

Portable - a device designed and capable of being carried or moved from one location to another. The device is not portable if it resides at the same location for more than 12 consecutive months.

Reasonably Available Control Technology (RACT) - control technology for existing sources that is generally considered to be those emission limits that would result from the application of demonstrated technology to reduce emissions.

Waste Gas - refers to gases generated at landfills or from the digestion of solid material at waste water treatment plants.

III. DESCRIPTION OF DISTRIBUTED GENERATION TECHNOLOGIES AND APPLICABILITY OF GUIDELINES

As discussed previously, this guideline is intended to be a companion to the 1999 ARB Power Plant Guidance. The 1999 report provides permitting guidance for electrical generation technologies using gas turbines 50 MW and larger. This report will provide additional guidance for other electrical generation technologies not covered in the 1999 Guidance. These technologies include gas turbines that are less than 50 MW and reciprocating engines. The fuels are further broken down into fossil fuels and waste gases such as landfill or digester gas.

This report will not provide guidance for electrical generation technologies that are used in emergency or portable applications. An emergency is when electrical or natural gas service fails or emergency pumping of water for fire protection or flood relief is required. Most emergency electrical generation units are diesel-fueled engines. The Board identified PM from diesel-fueled engines as a Toxic Air Contaminant in 1998. The ARB staff expects to present a proposed control measure, which will include emission standards for diesel-fueled engines, to the Board next year. Small backup generators (rated less than 50 horsepower) are already required to be certified under the ARB's Small Off-Road Engine (SORE) Program.

Electrical generation that is conducted for peak shaving or demand reduction purposes is governed by these guidelines.

This guidance does not apply to electrical generation equipment registered by the ARB's Statewide Portable Equipment Registration Program (PERP). A portable electrical generation unit which does not stay at any one location for more than 12 consecutive months is usually eligible for the PERP. Additional information on the ARB's PERP can be obtained from the ARB report: Proposed Amendments to the Regulation for the Statewide Portable Equipment Registration Program, October 1998.

IV. SUMMARY OF EXISTING REGULATIONS

A. District Programs

This section discusses the applicable air quality-related requirements for electrical generation at the local district level. These include district New Source Review programs, control measures adopted by districts pursuant to the State Implementation Plan (SIP), and rules and policies for the control of emissions of toxic air contaminants.

1. New Source Review

For most electrical generation sources, the primary air pollution control program of concern is New Source Review (NSR). NSR is a district preconstruction program established by the federal Clean Air Act that governs the construction of major new and modifying stationary sources. NSR is intended to ensure that these sources do not prevent the attainment or interfere with the maintenance of the national ambient air quality standards. Each district has adopted its own NSR rules to regulate the construction of new and modified sources of air pollutants. NSR requires the application of BACT and the mitigation of emission increases with offsets. With a few exceptions, the districts' definitions of BACT are equivalent to the federal requirement for lowest achievable emission rate (LAER). The application of BACT and offsets are discussed in detail in Appendix B of the Power Plant Guidance Report. The specific application of these criteria for electrical generation is discussed in Chapter V of this report.

2. Control Measures In The State Implementation Plan

As part of the effort to attain both State and federal ambient air quality standards, districts have been required to develop plans outlining the steps needed to attain these standards. This includes identifying control measures the district proposes to adopt and implement to generate the necessary emissions reduction. These control measures typically identify the target category and the proposed level of emission reduction. A brief discussion of the most stringent SIP control measures related to electrical generation is provided in Appendix B.

3. Toxic Air Pollutants Programs

There are several programs used by districts to regulate toxic air pollutants, including Toxic New Source Review, the Air Toxics "Hot Spots" Information and Assessment Act, and the ARB's Toxic Air Contaminant Program.

Currently, four districts have adopted Toxic New Source Review rules and approximately 15 districts have policies. Most of these rules and policies use an approach that incorporates risk levels that trigger the installation of Toxic Best Available Control Technology (T-BACT). Risk levels above prescribed thresholds can result in a permit denial.

The Air Toxics "Hot Spots" Information and Assessment Act establishes a formal air toxics emission inventory risk quantification and risk reduction program for districts to manage. The goal of the Air Toxics "Hot Spots" Act is to collect emissions data indicative of routine predictable releases of toxic substances to the air, identify facilities having localized impacts, evaluate health risks from exposure to the emissions, notify nearby residents of significant risks, and reduce risk below the determined level of significance.

The Toxic Air Contaminant Identification and Control Act created California's two-step program to reduce exposure to air toxics. During the first step (risk identification), the ARB and the Office of Environmental Health Hazard Assessment (OEHHA) determine if a substance should be formally identified as a toxic air contaminant (TAC) in California. In the second step (risk management), the ARB reviews the emission sources of an identified TAC to determine if any regulatory action is necessary to reduce the risk. If the ARB subsequently adopts airborne toxic control measures (ATCM), then districts are required to adopt and enforce control measures at least as stringent as those adopted by the ARB. To date, ARB has adopted nine ATCMs.

B. ARB Programs

This section describes various ARB activities related to electrical generation.

1. Guidance for Power Plant Siting and Best Available Control Technology

The ARB's September 1999 Power Plant Guidance, provides guidance to assist districts in the permitting of electrical generation that is subject to the California Energy Commission's (CEC) power plant siting process for power plants that generate 50 MW or more. Guidance was provided for BACT for criteria pollutant emissions from simple cycle and combined cycle natural gas fired electrical generation technology. In addition, guidance was provided for the other aspects of permitting, such as satisfying emission offset requirements and preparing health risk assessments.

2. Retrofit Of Electrical Generation Facilities

On May 22, 2001, Governor Davis signed SB 28X (Sher). This bill requires the ARB, in consultation with districts and the Independent System Operator, to adopt regulations to establish emission control retrofit requirements for electrical generation facilities in a manner that protects public health and the environment. SB 28X requires the ARB to adopt regulations by July 1, 2002. The mandated retrofits must be completed by December 31, 2004, unless a later date is needed to maintain electric system reliability, or unless the operator intends to repower the facility.

3. Diesel Risk Reduction Plan/Risk Management

In September 2000, the Board approved a comprehensive Diesel Risk Reduction Plan (Plan) to reduce diesel particulate matter emissions from new and existing diesel-fueled engines and vehicles. Diesel particulate was identified as a TAC by the Board in August, 1998. The Plan was promulgated pursuant to the Toxic Air Contaminant Identification and Control Act.

The Plan approved by the Board identifies 14 measures that will be developed over the next several years. The goal of the Plan is to reduce diesel PM emissions and the associated health risk by 75 percent in the year 2010 and 85 percent or more by the year 2020. Some of the proposed measures include: new emissions standards for diesel-fueled engines, retrofit of existing stationary prime and emergency standby diesel-fueled engines (an electrical generation technology), and retrofit of existing portable diesel-fueled engines. See the ARB diesel website (http://www.arb.ca.gov/diesel/dieselrrp.htm) for information about the schedule for developing these various measures.

The Board also approved guidance to assist districts in risk management decisions associated with the permitting of new stationary diesel-fueled engines. The guidance document contains a recommendation that new stationary diesel-fueled engines meet specific technology requirements or an equivalent performance standard to reduce diesel particulate matter. Additional requirements must be satisfied for engines that could operate more than 300 hours annually. In general, the guidance recommends that non-emergency engines satisfy a PM emission standard of 0.02 grams per brake horsepower-hour) (g/bhp-hr). For emergency standby engines, engines that operate 100 hours or less on an annual basis, the guidance recommends that the engines satisfy a 0.1 g/bhp-hr PM performance standard. See the ARB staff report, Risk Management Guidance for the Permitting of New Stationary Diesel-Fueled Engines, October 2000, for more details.

4. Reasonably Available Control Technology (RACT)/Best Available Retrofit Control Technology (BARCT) For Stationary Spark Ignited Engines

The ARB staff has issued a proposed RACT/BARCT determination for stationary spark ignited engines. Recommendations were provided for both RACT and BARCT levels for NOx, VOC, and CO for several categories based upon engine type. The most recent recommendations are contained in the ARB draft staff report entitled Proposed Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology For Stationary Spark-Ignited Internal Combustion Engines, April 2001. The draft report has been circulated among district staff for their review and the report is expected to be finalized in 2002. In addition, in conjunction with the ARB's effort to reduce diesel PM emissions from stationary diesel-fueled engines, the ARB staff will also be evaluating RACT and BARCT levels for NOx, VOC, and CO emissions from stationary diesel-fueled engines.

5. Risk Management Guidelines For New And Modified Sources Of Toxic Air Pollutants

The ARB staff provided guidance to assist districts in making permitting decisions for new and modified stationary sources of toxic air pollutants. This guidance is contained in the ARB staff report: Risk Management Guidelines for New and Modified Sources of Toxic Air Pollutants, 1993. Guidance was provided for managing potential cancer and noncancer health risks and is applicable to electrical generation sources.

C. United States Environmental Protection Agency Programs

This section describes various guidance and programs promulgated by the United States Environmental Protection Agency (U.S. EPA) or contained in the federal Clean Air Act that may affect electrical generation.

1. Permitting Programs

The federal Clean Air Act established two distinct preconstruction permit programs governing the construction of major new and modifying stationary sources: NSR for nonattainment areas and Prevention of Significant Deterioration (PSD) for attainment areas. As discussed above, districts have implemented the requirements of NSR. For PSD, districts with federal delegation implement their own PSD program. Otherwise, U.S. EPA implements the PSD program for districts without federal delegation authority. Both programs require control technology (BACT for PSD and LAER for NSR) and offsets.

2. Other Programs

New source performance standards (NSPSs) are regulations adopted by the U.S. EPA that define emission limits, testing, monitoring and record keeping for certain categories of sources or processes (Sections 111 and 129 of the Federal Clean Air Act; 40 CFR Part 60). There is a NSPS for turbines (Subpart GG of 40 CFR Part 60), previously discussed in the 1999 ARB power Plant Guidance. No NSPS has been proposed for reciprocating engines.

The federal program for national emission standards for hazardous air pollutants (NESHAP) is applicable to new and existing sources emitting over ten tons per year (TPY) of one hazardous air pollutant (HAP) or 25 TPY of a combination of HAPs (Section 112 of the Federal Clean Air; 40 CFR Part 61 and 63). A NESHAP may include a requirement for maximum achievable control technology (MACT). Proposed MACT standards are expected to be released for public comment in 2001 for toxic emissions from spark-ignited and compression ignition engines, as well as, gas turbines.

D. California Energy Commission Program

The California Energy Commission (CEC) has the exclusive authority to approve the construction and operation of power plants that will use thermal energy and have electrical generation capacities of 50 MW or greater. The Power Plant Guidance contains a summary of the CEC power plant siting process.

E. States' Programs Related to Distributed Generation

On May 29, 2001, the State of Texas adopted a regulation allowing the issuance of an air permit (standard permit) for electric generating units if certain requirements are satisfied. Instead of meeting the requirements of the standard permit, applicants in Texas have the option to obtain permits through the normal NSR program.

In the standard permit for electrical generation units, the initial standards for the non-attainment area of Texas are generally consistent with BACT requirements in California, and for the attainment area of Texas, the initial standards are consistent with RACT requirements. For technologies that are less than 10 MW and located in the non-attainment area of Texas, units installed prior to December 31, 2004 are subject to a NOx emission standard of 0.44 lb/MW-hr. Electrical technologies that are less than 10 MW and installed after December 31, 2004, are subject to a more stringent NOx emission standard of

0.14 lb/MW-hr, equivalent to a gas turbine emitting 5 ppmvd NOx. Finally, all electrical technologies larger than 10 MW and operated more than 300 hours annually are also subject to the NOx emission standard of 0.14 lb/MW-hr.

Connecticut plans to propose a general permit that will initially be set at RACT levels, but will become more stringent by 2005. If the emissions from the proposed electrical generation unit exceed the standard, the project applicant would be required to mitigate the amount of emissions that is above the standard. New York is establishing a work group to begin the process of developing a program.

Since January 2001, the ARB staff has participated in the Distributed Generation Emissions Collaborative Working Group. The Regulatory Assistance Project (RAP) is organizing and coordinating the activity of the Collaborative Working Group. The Collaborative Working Group is composed primarily of representatives from various State public utility commissions, State air quality programs, manufacturers, and the National Resources Defense Council. The goal of the group is to develop a national model rule for emissions from DG by September 2001. Information on the activities of the Collaborative Working Group is available at http://www.rapmaine.com.

V. BACT FOR ELECTRICAL GENERATION TECHNOLOGIES

A. Introduction

This chapter summarizes the ARB staff analysis of BACT determinations for the following electrical generation technologies: stationary natural gas fired turbines ("gas turbines") having a power rating of less than 50 MW using natural gas or waste gases; and stationary reciprocating engines using fossil fuels or waste gases. This chapter also summarizes information about combustion and add-on control technologies that can be used to reduce emissions of NO_X, CO, and VOC. General guidance for performing a BACT evaluation is contained in Appendix B of the1999 ARB Power Plant Guidance.

In most district permitting rules, BACT is defined as the most stringent limitation or control technique:

1) which has been achieved in practice,

2) is contained in any SIP approved by the U.S. EPA, or

3) any other emission control technique, determined by the Air Pollution Control Officer to be technologically feasible and cost effective.

SB 1298 defined BACT to have the same meaning as defined in the California Health and Safety Code section 40405. Section 40405 defines BACT as an emission limitation that will achieve the lowest achievable emission rate for the source to which it is applied. Lowest achievable emission rate means the most stringent of the following: (1) the most stringent emission limitation that is contained in the SIP for the particular class or category of source, unless the owner or operator of the source demonstrates that the limitation is not achievable; (2) the most stringent emission limitation that is achieved in practice by that class or category or source. This definition is consistent with the first two provisions of the district BACT definition discussed above.

The ARB staff recommended BACT emission levels are summarized in Tables IV-1 and IV-2. These NOx, VOC, and CO levels are expressed in terms of lb/MW-hr. This convention, which is consistent with the ARB's proposed DG certification program, provides recognition for efficient use of fuels and reduced emissions of greenhouse gases.

These recommended BACT emission levels are current at the publishing time of this guidance, and are based upon the most stringent emission level contained in any SIP approved by the U.S. EPA or the most stringent emission level achieved in practice.

Table IV-1:
Summary Of BACT For The Control Of Emissions From Stationary Gas Turbines Used In Electrical Generation*

Equipment Category	NOx (lb/MW-hr)	VOC (lb/MW-hr)	CO (lb/MW-hr)
< 3 MW	0.5	0.1	0.4
3 - 12 MW	0.25	0.04	0.2
> 12 - < 50 MW	0.20	0.03	0.15
Waste gas fired	1.25	na	na

*all standards based upon 3-hour rolling average

Table IV-2:
Summary Of BACT For The Control Of Emissions From Reciprocating Engines Used In Electrical Generation

Equipment Category	NOx (lb/MW-hr)	VOC (lb/MW-hr)	CO (lb/MW-hr)	PM (lb/MW-hr)
Fossil fuel fired	0.5	0.5	1.9	0.06
Waste gas fired	1.9	1.9	7.8	NA

ARB will use the California Air Pollution Control Officer's Association (CAPCOA) BACT Clearinghouse to keep district staff apprised of changes to BACT levels, particularly in identifying additional achieved in practice determinations.

District BACT requirements will change if operational data or advances in technology demonstrate that lower levels have been achieved or are achievable at a reasonable cost. These emission levels should be used by Districts as a starting point in conducting a case-by-case BACT determination. For example, some of the technically feasible technologies discussed below, such as SCONOX or XONON, should be evaluated as part of the case-by-case BACT determination. Finally, the specific conditions of each application may justify a departure from the ARB's staff recommended BACT emission levels. Factors that may affect a BACT determination include, but are not limited to:

- area attainment status,
- for gas turbines, use of aeroderived versus industrial frame gas turbine for simple-cycle power plant configuration, and
- use and function of electrical generation technology.

It is the responsibility of the permitting agency to make its own BACT determination for the class and category of electrical generation technology application. The BACT emission levels are intended to apply to the emission concentrations as exhausted from the stacks.

B. Gas Turbines Less Than 50 Megawatts

1. Current Control Technologies Being Used

a. State Implementation Plan Measures

There are several SIP control measures specifying reductions in NOx emissions from gas turbines. The most stringent of these measures has been adopted by the South Coast Air Quality Management District (SCAQMD) and Antelope Valley Air Pollution Control District (AVAPCD) with NOx emission standards based upon size, annual operating hours, and control system used. The SCAQMD and AVAPCD requirements vary from 25 parts per million by volume, dry (ppmvd) for the smallest turbines (rating from 0.3 to under 2.9 MW) to 9 ppmvd for turbines larger than 2.9 MW.

b. Control Techniques Required As BACT

The control techniques used for gas turbines have been described in detail in the 1999 ARB Power Plant Guidance. In summary, a combination of control techniques are available. For the control of NOx emissions, techniques include combustion modifications and post combustion controls. Combustion modifications include techniques such as XONON (a catalytic combustion), low NOx combustors, and water/steam injection. Post combustion add-on systems such as selective catalytic reduction (SCR) and SCONOX have been used to achieve the lowest emission levels required by recent BACT determinations.

The efficiency of some NO_X control techniques is affected by exhaust temperature. Catalysts used for SCR are not as efficient in controlling NO_X at the high temperatures associated with uncooled exhaust. Gas turbine emissions from combined-cycle and cogeneration operations remove heat from the exhaust allowing the SCR system to operate at optimum conditions. For simple cycle applications within the size range addressed in this report, the same levels can be achieved with a combination of high temperature catalyst and cooling of the exhaust. For the reduction of VOC and CO emissions, the technology of choice is oxidation catalyst.

The ARB staff reviewed BACT determinations conducted by California districts and other states for gas turbines used in power plant configurations. The result of this review supports establishing recommended BACT emission levels for three class or categories based upon the electrical output of the power plant. These categories are turbines rated at less than 3 MW, turbines rated at 3

MW up to 12 MW, and turbines rated larger than 12 MW. The 12 MW cutoff is based upon the greater efficiencies of gas turbines in this category—a significant consideration when the emission level is expressed in lb/MW-hr. The lower cutoff is based upon the SCAQMD guidelines establishing a BACT standard for turbines less than 3 MW.

1. Gas Turbines Less Than 3 MW

The most stringent BACT levels for gas turbines less than 3 MW are expressed in BACT guidelines for the SCAMQD and Bay Area Air Quality Management District (BAAQMD). BACT Guidelines for the SCAQMD (for turbines less than 3 MW) and BAAQMD (for turbines less than 2 MW), specify BACT at 9 ppmvd at 15 percent O_2 for NOx, 5 ppmvd at 15 percent O_2 for VOC (BAAQMD only), 10 ppmvd at 15 percent O_2 for CO, and 9 ppmvd at 15 percent O_2 for ammonia. In addition, the BAAQMD Guidelines identify as technically feasible and cost effective a NOx level of 5 ppmvd at 15 percent O_2 based upon the application of catalytic combustion or high temperature SCR system with combustion modifications.

The most stringent BACT level expressed in a preconstruction permit is for the Genxon Power Systems facility in Santa Clara. The Genxon Power Systems facility consists of a Kawasaki M1A-13 turbine (1.5 MW) equipped with XONON combustors. The XONON technology is discussed in detail in Section V.B.1.d.1 of this document.

2. Gas Turbines From 3 MW To 12 MW

The most stringent BACT level for NOx emissions from gas turbines between 3 MW and 12 MW, as required in a preconstruction permit, is 5 ppmvd at 15 percent O_2 averaged over 3 hours. The Saint Agnes Medical Center, the University of California, San Francisco and two projects for Alliance Colton facilities have been permitted at this level. The Saint Agnes Medical Center electrical generation unit consists of a Solar Centaur 40 (3.5 MW) equipped with dry low NOx combustors and SCR. The unit at the University of California, San Francisco uses a Solar Taurus 60 (5 MW) with heat recovery and is equipped with water injection and SCR. Finally, the Alliance Colton units are based upon a General Electric 10B1 (10 MW) operated in simple cycle mode and equipped with either XONON or SCR. (The BACT levels for the Alliance Colton facilities are based upon a one-hour average.) With regard to ammonia slip, the most stringent BACT level established in a preconstruction permit is 10 ppmvd at 15 percent O_2.

With regard to VOC and CO, the most stringent level appearing in a preconstruction permit is 2 ppmvd at 15 percent O_2 for VOC and 6 ppmvd at 15 percent O_2 for CO. The University of California, San Francisco facility (3-hour rolling average) and the two electrical generation units for Alliance Colton (1-hour rolling average) are permitted at this level. This BACT level, consistent with the1999 ARB Power Plant Guidance, is achievable using oxidation catalyst.

3. Gas Turbines Greater Than 12 MW

The most stringent BACT level required is in a preconstruction permit for the NRG Energy Center Round Mountain located in the San Joaquin Valley. The BACT determination was 2 ppmvd at 15 percent O_2 for NOx averaged over 3 hours. The determination is for a General Electric LM6000 enhanced sprint gas turbine with a heat recovery steam generator and equipped with water or steam injection, SCR, and oxidation catalyst. In addition, Northern California Power in Lodi was permitted at 3 ppmvd at 15 percent O_2 averaged over 3 hours for NOx. The facility consists of a General Electric LM5000 gas turbine operated in a simple-cycle mode and equipped with steam injection, SCR, and oxidation catalyst.

With regard to VOC, CO, and ammonia, the most stringent level appearing in a preconstruction permit is 2 ppmvd at 15 percent O_2 for VOC, and 5 ppmvd at 15 percent O_2 for ammonia for the NRG Energy Center Round Mountain facility. For this project, a BACT determination was not made for CO. For CO, the most stringent level appearing in a preconstruction permit is 6 ppmvd at 15 percent O_2. This has been specified for a number of projects, including Redding Power and the Los Angeles Department of Water and Power's Valley facility.

c. Emission Levels Achieved In Practice

1. Gas Turbines Less Than 3 MW

The most stringent level achieved in practice is for a Kawasaki turbine (1.5 MW) equipped with the XONON combustors located at Genxon Power Systems. This turbine has achieved NOx levels of 2-3 ppmvd at 15 percent O_2. The XONON technology is discussed in detail in Section V.B.1.d.1 of this document.

2. Gas Turbines From 3 MW To 12 MW

Two generating facilities have achieved NOx emission levels of 5 ppmvd at 15 percent O_2. These include the University of California, San Francisco, discussed above, and the generating facility at California Institute of Technology (CalTech), Pasadena. The unit at CalTech consists of a Solar Centaur 50 (4.6 MW) turbine operated in a combined cycle mode and is equipped with water injection and SCR. The University of California, San Francisco facility is also equipped with oxidation catalyst. With the catalyst, the University of California, San Francisco facility has reduced VOC emissions to the detection level and CO emissions are at 1 ppmvd—well under the BACT levels of 2 ppmvd at 15 percent O_2 and 10 ppmvd at 15 percent O_2, respectively. In all cases, these levels have been demonstrated for over three years, based upon three consecutive annual source tests and continuous emissions monitoring (CEM) data.

3. Gas Turbines Greater Than 12 MW

The lowest level achieved in practice is for the above mentioned Northern California Power facility in Lodi, which has operated since early 1999. Based upon CEM data and annual inspections, the unit has met the 3 ppmvd NOx limit since startup. The latest compliance test indicated NOx emissions were below 3 ppmvd at 15 percent O_2 and emissions of CO were measured at about 12 ppmvd at 15 percent O_2.

Several other facilities in the San Joaquin Valley have been permitted at NOx level between 3.6 to 4.5 ppmvd at 15 percent O_2, based upon a 3-hour average. These facilities are Live Oak Limited, Double C Limited, and High Sierra Limited. Double C Limited and High Sierra Limited consists of a General Electric LM2500 turbine (25 MW) and heat recovery steam generator. Live Oak Limited consists of a General Electric LM5000 turbine (49 MW) and heat recovery steam generator. All three facilities produce steam for use at an oilfield, and are equipped with SCR and oxidation catalyst. The Live Oak Limited facility has consistently maintained NOx emission levels below 3 ppmvd at 15 percent O_2 since starting up in 2000. Both the Double C Limited and High Sierra Limited facilities were permitted at a higher NOx limit, 4.5 ppmvd at 15 percent O_2, but have typically been between 2.5 to 3.5 ppmvd at 15 percent O_2 based upon three years of annual testing. Finally, the latest compliance test for Live Oak Limited also indicated VOC and CO emissions were below the detection level.

In addition, the Federal Cold Storage Cogeneration facility has demonstrated levels of 2 ppmvd at 15 percent O_2 since 1996, based upon continuous emissions data collected over that period. This facility consists of a 25 MW General Electric LM2500 gas turbine operated in combined cycle mode generating a total of 32 MW. The gas turbine utilized water injection in conjunction with SCONOX.

d. More Stringent Control Techniques

There are a number of NOx control techniques that have not reached full commercial status. These technologies, which include XONON and SCONOX, have been demonstrated successfully on several applications. However, at this time, they have not been widely implemented.

1. XONON

At the Genxon Power Systems facility in Santa Clara, a Kawasaki M1A-13 turbine (1.5 MW) equipped with XONON combustors has operated for over 8,000 hours. The XONON technology is a flameless catalytic system integrated into the combustor in order to lower temperatures. As discussed above, the Kawasaki turbine equipped with XONON achieved NOx levels of 2-3 ppmvd at 15 percent O_2, as well as, VOC levels of less than 3 ppmvd at 15 percent O_2, and CO levels of 4 ppmvd at 15 percent O_2. In addition, Catalytica Combustion Systems ("Catalytica"), the manufacturer of XONON, has applied to the ARB's Equipment and Process Precertification Program requesting an independent verification of their claim that the Kawasaki turbine M1A-13X equipped with XONON demonstrates emissions of 2.5 ppmvd at 15 percent O_2 for a one-hour rolling average and 2.0 ppmvd at 15 percent O_2 for a three-hour rolling average.

If this technology is scaled-up and made available for other turbines, it may represent one of the most efficient combustion control options for NO_X for gas turbines. Catalytica is working with General Electric to implement the XONON technology on larger turbines. Two projects have been proposed using XONON in a General Electric turbine model 10B1 (10.5 MW) and a General Electric frame 7-F (168 MW).

2. SCONOX

The SCONOX technology has been implemented with success at the Federal Cold Storage Facility and the Genetics Institute facility in Massachusetts. In addition, the University of California, San Diego facility just finished commissioning testing. SCONOX is also proposed for the Redding Power facility in Shasta, which would be the largest turbine application to date for this technology.

The Federal Cold Storage Facility consists of a General Electric LM2500 gas turbine in combined cycle mode for a total electrical generation of 32 MW. The turbine exclusively fires natural gas, utilizes water injection in conjunction with SCONOX, and has demonstrated levels of 2 ppmvd at 15 percent O_2 since 1996, based upon continuous emissions data. The ARB, through its Equipment Precertification Program, has verified the emissions of NOX of 2 ppmvd at 15 percent O_2 over a 3-hour rolling average for the Federal Cold Storage Cogeneration facility. A revised formulation suggests that even lower levels of NOx could be achieved.

The Genetics Institute facility consists of a Solar Taurus 60 (5 MW) equipped with dry low NOx combustors and SCONOX. When natural gas is used as the primary fuel, the NOx emissions have been below 2 ppmvd at 15 percent O_2. However, when the turbine operates for long periods of time using oil, which appears to be the normal operating scenario, the SCONOX technology has experienced masking problems which reduces the effectiveness of the technology in reducing NOx emissions. The masking is reversible, but requires cleaning of the catalyst, and therefore shutdown of the turbine. EmeraChem (formerly known as Goal Line Environmental Technologies), the developer of the SCONOX technology, has since made modifications to the SCONOX systems at Genetics Institute such that oil usage no longer adversely affects the SCONOX system.

At University of California, San Diego, two 12.5 MW turbines and control technology have recently become operational. The July 2001 compliance test indicates NOx emissions levels are below 1 ppmvd at 15 percent O_2 for both turbines. However, prior to the compliance test, the facility was operating under a variance because the facility could not meet its permit limits within the commissioning period (90 days) allocated for shakeout and fine-tuning the facility's operation.

The SCONOX technology has relatively few installations and the largest gas turbine on which it is applied is 25 MW (the Federal facility generates a total of 32 MW including the 7 MW steam turbine). In addition, the SCONOX technology, when compared to SCR, is substantially more expensive, and, as discussed above, there have been technical issues at each of its installations regarding the initial implementation of the technology. While the ARB staff is not considering the levels achieved by SCONOX for the purposes of establishing guideline levels, district staff should continue to consider SCONOX in BACT determinations.

e. Concerns Regarding NOx Emissions Measurement

As discussed above, NO_X emissions from gas-turbine power plants employing advanced combustor design and post-combustion controls have been reduced to levels of approximately 2 to 3 ppmvd at 15 percent O_2. Current emission measurement methods for source testing and CEM were developed for sources with higher emission concentrations. As a result, many federal and State emission measurement methods have become obsolete for emission assessment and enforcement purposes. The ARB convened a Committee on Low Emission Measurement (Committee) to provide recommendations to revise the existing test method. This Committee includes representatives from the U.S. EPA, ARB, districts, manufacturers (testing equipment, turbines, and related equipment), and companies with emission measurement expertise. In addition, the University of California, Riverside (UCR) has been investigating the issue and is expected to issue a report that will include recommendations for revising the measurement methods. The Committee will consider UCR's report in making its recommendations. After the Committee makes its recommendations, the ARB will revise the affected test methods and bring them to the Board for approval.

f. BACT Recommendations

As discussed above, the ARB staff recommends the gas turbine emission category be subdivided based upon the electrical generation capacity of the gas turbine: less than 3 MW, 3 MW to 12 MW, and greater than 12 MW. Table IV-1 summarizes the recommended BACT levels, in terms of lb/MW-hr, for each of these classes of categories. Similarly, Table IV-2 summarizes the recommended BACT levels, in terms of concentration or ppmvd. The levels in both tables should be based upon a three-hour rolling average.

As discussed above, for gas turbines less than 3 MW, the ARB staff recommends using the guidelines levels recommended in the BAAQMD (achieved in practice levels) and SCAQMD BACT Guidelines as BACT. These levels are 9 ppmvd at 15 percent O_2 for NOx, 5 ppmvd at 15 percent O_2 for VOC, and 10 ppmvd at 15 percent O_2 for CO. Ammonia slip was also limited to 9 ppmvd at 15 percent O_2. The ARB staff is not aware of any BACT determinations, other than the Genxon Power Systems facility, for turbines rated at less than 3 MW.

The BACT recommendations for gas turbines between 3 MW and 12 MW, are based upon the emission level achieved in practice for the generating unit at the University of California, San Francisco. These levels are 5 ppmvd at 15 percent O_2 for NOx, 2 ppmvd at 15 percent O_2 for VOC, 6 ppmvd at 15 percent O_2 for CO, and 10 ppmvd at 15 percent O_2 for ammonia slip. The unit at the University of California, San Francisco, which has operated since 1998, uses a Solar Taurus 60 (5 MW) with heat recovery and is equipped with water injection, SCR, and an oxidation catalyst. The San Francisco facility has achieved NOx emissions of 5 ppmvd at 15 percent O_2 level, reduced VOC emissions to the level of detection, and reduced CO emissions to 1 ppmvd at 15 percent O_2. In addition, the Cal Tech generating unit has also demonstrated a NOx level of 5 ppmvd at 15 percent O_2 level.

For gas turbines larger than 12 MW, the ARB staff recommendations are based upon the levels achieved in practice levels for Northern California Power facility in Lodi, and several electric generating facilities located at oil fields, including the Live Oak Limited, Double C Limited, and High Sierra Limited facilities. Based upon the achieved in practice levels for these facilities, the levels recommended as BACT are 5 ppmvd at 15 percent O_2 for NOx, 2 ppmvd at 15 percent O_2 for VOC, 6 ppmvd at 15 percent O_2 for CO and 10 ppmvd at 15 percent O_2 for ammonia slip. Both the Northern California Power facility and the

Live Oak Limited facility have been below 3 ppmvd at 15 percent O_2 for NOx. The Northern California Power facility consists of a General Electric LM5000 operated in simple cycle mode and the Live Oak Limited facility consists of a General Electric LM5000 gas turbine and heat recovery steam boiler. In addition, for the Live Oak Limited facility, the VOC were below the detection level, CO levels below 2 ppmvd at 15 percent O_2, and ammonia levels below 10 ppmvd at 15 percent O_2. Both the Double C Limited and High Sierra Limited facilities, which consists of a General Electric LM2500 turbine and heat recovery steam generator, were permitted at a higher NOx limit, 4.5 ppmvd at 15 percent O_2, but have typically been between 2.5 to 3.5 ppmvd at 15 percent O_2.

The above recommendations are largely based upon levels achieved in practice. District permitting staffs are encouraged to evaluate these BACT levels represented by these projects as part of the technical feasibility portion of the case-by-case BACT determination for electrical generation projects. For example, district permitting staffs are encouraged to evaluate the technical feasible and cost effectiveness of more stringent BACT levels or the use of advance control technologies including the SCONOX or XONON technologies. Finally, the levels are consistent with the recommended BACT level from the 1999 ARB Power Plant Guidance.

The following table summarizes the recommended levels for stationary gas turbines used in electrical generation:

Table IV-3:
Summary Of BACT For The Control Of Emissions From Stationary Gas Turbines Less Than 50 MW Used In Electrical Generation*

Equipment Category	NOx (ppmvd @ 15% O_2)	VOC (ppmvd @ 15% O_2)	CO (ppmvd @ 15% O_2)
< 3 MW	9	5	10
3MW - <50 MW	5	2	6

*all standards based upon 3-hour rolling average

2. Future Developments

SB 1298 directs the ARB, at the earliest practicable date, to make its BACT determination guidance to the districts equivalent to that of permitted central station power plants in California. In order for all electrical generation technologies to achieve the same emission level as a central station power plant equipped with BACT emission control technologies will need to improve, as will the efficiencies of reciprocating engines.

The control technologies proposed for turbines less than 50 MW are the same technologies being used for the central station power plants. For turbines larger than 12 MW, the levels achieved are approaching the same level achieved by central station power plants equipped with BACT, in terms of concentration (or ppmvd). However, because of the higher efficiency of the gas turbine combined cycle power plants, the 2 ppmvd at 15 percent O_2 NOx level achieved by a 45 MW turbine will be less stringent, based upon lb/MW-hr, than the level achieved by a central station power plant equipped with BACT. For turbines rated at less than 12 MW, BACT has not achieved the same level, on a concentration basis, as a central station power plant equipped with BACT.

As discussed above, the larger turbines are more efficient than the smaller turbines. Large turbines are approaching efficiencies of 40 percent in converting the energy content of the fuel to electrical energy, and when used in a combined cycle application, the efficiency approaches 56 percent. By comparison, turbines less than 10 MW have efficiencies of 32 percent or less. There are efforts underway to improve the efficiencies of the smaller turbines. For example, Solar Turbines is working with the Department of Energy (DOE) to develop an advance combustion system turbine that can achieve 40 percent efficiency--the same efficiency level enjoyed by the large turbines.

In summary, for gas turbines rated at 50 MW and less, to reach the equivalent emission levels, expressed as lb/MW-hr, as central station power plants equipped with BACT, the emission control systems will have to reduce emissions further and the efficiency of the turbines will have to improve.

C. Reciprocating Engines Using Fossil Fuel

1. Current Control Technologies Being Used

a. State Implementation Plan Measures

Several districts have adopted SIP control measures specifying reductions in NOx emissions from reciprocating engines. The most stringent of these measures has been adopted by SCAQMD, AVAPCD, and Ventura County Air Pollution Control District (VCAPCD). Both measures set emission standards for NOx, VOC, and CO. The SCAQMD and AVAPCD requires reciprocating engines, with no distinction as to the type of fuel used, to meet the following emission standards: 36 ppmvd at 15 percent O_2 for NOx, 250 ppmvd at 15 percent O_2 for VOC, and 2,000 ppmvd at 15 percent O_2 for CO. Alternate levels, which are higher than the general requirement, for NOx and VOC are allowed, based upon the efficiency of the engine.

The VCAPCD requirements for reciprocating engines vary based upon the type of engine and whether the standard can be satisfied by meeting an emission standard or achieving a specified percentage of emission reduction. NOx emission standards are set at 25 ppmvd at 15 percent O_2 for rich-burn engines, 45 ppmvd at 15 percent O_2 for lean-burn engines, and 80 ppmvd at 15 percent O_2 for diesel-fueled engines. Similarly, the VOC standard varies from 250 to 750 ppmvd at 15 percent O_2 and the CO standard is 4,500 ppmvd at 15 percent O_2 for all type of engines. The emission reduction component applies to NOx only and reductions of 90 to 96 percent must be achieved, with the specific level based upon the engine type.

b. Control Techniques Required As BACT

As discussed below, some districts are beginning to develop BACT requirements that are fuel neutral. For example, the SCAQMD BACT Guidelines for minor sources specifies that reciprocating engines used in nonemergency applications and less than 2,064 bhp satisfy the following levels: 0.15 grams/brake horsepower-hour (g/bhp-hr) for NOx and VOC, and 0.6 g/bhp-hr for CO. Larger engines are subject to a NOx standard that is based upon the efficiency of the engine. Based upon this approach, the NOx BACT level can only be satisfied by a well-controlled natural gas fueled reciprocating engine. At this time, diesel-fueled engines cannot achieve this emission level. Consequently, the discussion below focuses only on the emission levels achieved by natural gas fueled reciprocating engines.

To reduce NOx emissions from natural gas fueled reciprocating engines to the levels required by SCAQMD, post-combustion controls are necessary. Nonselective catalytic reduction (NSCR) or three-way catalyst technology is used for rich-burn engines and SCR for lean-burn engines. The major difference between rich-burn and lean-burn engines is in the amount of excess air used for combustion. Rich-burn engines use a nearly equal mixture of air and fuel, while lean-burn engines use significantly more air than fuel. Three-way catalyst technology, because of technical operating requirements, works well with rich-burn engines and is not applicable to lean-burn engines. In addition, to achieve the 0.15 g/bhp-hr level, a premium catalyst is necessary that is more efficient in reducing NOx emissions than the standard catalyst.

Conversely, lean-burn engines are significantly more efficient in converting the energy in the fuel into electrical energy. Because the ARB staff is recommending BACT levels in terms of lb/MW-hr, electrical generation technologies with higher electrical efficiency will have an advantage. Lean-burn engines typically achieve 38 percent electrical efficiency, with some lean-burn engines exceeding 40 percent electrical efficiency. In comparison, rich-burn engine's electrical efficiency is typically 32 percent, but can be as low as 20 percent.

Similarly, BACT levels for CO and VOC emissions are also based upon post-combustion controls. NSCR also reduces CO and VOC emissions while oxidation catalyst is used to reduce CO and VOC emissions from lean-burn engines.

The most stringent BACT limits for a rich-burn engine that have been specified in a preconstruction permit is for the Aera Energy facility located at an oilfield in the San Joaquin Valley. The BACT limits are 0.071 g/bhp-hr (4 ppmvd at 15 percent O_2)[1] for NOx, 0.069 g/bhp-hr (11 ppmvd at 15 percent O_2) for VOC, and 0.6 g/bhp-hr (56 ppmvd at 15 percent O_2) for CO. This determination is based upon a vendor guarantee for the emission level for either a 800 bhp Superior 8G-825 natural gas fired engine or a 1,478 bhp Waukesha 7042 GSI engine, depending upon which engine the project proponent is ultimately provided, equipped with a three-way catalyst. Once installed, these engines would be driving natural gas compressors.

Prior to the issuance of the Aera Energy permit, the most stringent BACT limits for a rich-burn engine were: 0.15 g/bhp-hr for NOx and VOC, and 0.6 g/bhp-hr for CO. As discussed above, this level has been specified as BACT for reciprocating engines (applicable to both rich-burn and lean-burn natural gas fueled engines as well as diesel-fueled engines) used in nonemergency applications in the SCAQMD BACT Guidelines and has been specified as BACT in the SCAQMD since 1998. This BACT level has been applied to a number of engines in other districts, including Santa Barbara County Air Pollution Control District and VCAPCD.

For lean-burn engines, the most stringent BACT limits have been specified in a preconstruction permit for NEO California Power LLC for their facility at Chowchilla. The BACT limits are 0.07 g/bhp-hr (5 ppmvd at 15 percent O_2) for NOx, 0.15 g/bhp-hr (30 ppmvd at 15 percent O_2) for VOC, 0.1 g/bhp-hr (10 ppmvd at 15 percent O_2) for CO, and ammonia slip is limited to 10 ppmvd at 15 percent O_2. This determination is for a 4,157 hp Deutz TBG632V16 lean burn engine equipped with SCR and oxidation catalyst. These engines began operation in mid-June, 2001 and compliance tests results should be available by the end of 2001. Similar BACT determinations have been made in preconstruction permits for NEO California Power LLC for their facility at Red Bluff and for JST Energy LLC for their facility at Red Bluff. In this case, both determinations are for 3,928 hp Wartsilla 18V220S engines equipped with SCR and oxidation catalyst. The NEO California Power LLC facility at Red Bluff initiated operation in August, 2001.

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1 the concentrations provided with the equivalent g/bhp-hr are estimates and actual concentrations may vary. See Appendix C for methodology used to convert between concentrations to g/bhp-hr or to lb/MW-hr.

c. Emission Levels Achieved In Practice

The most stringent levels achieved in practice for a rich-burn engine are 0.15 g/bhp-hr (9 ppmvd at 15 percent O_2) for NOx, 0.15 g/bhp-hr (25 ppmvd at 15 percent O_2) for VOC, and 0.6 g/bhp-hr (56 ppmvd at 15 percent O_2) for CO. A number of engines varying in size from 86 bhp to 747 bhp engines equipped with three-way catalyst have satisfied these emission standards. The emissions during initial operation are typically very low (50 percent or less of the applicable BACT standard--see information in Appendix B) in the first year due to the high efficiency of the fresh catalyst. As the catalyst ages, the efficiency of the catalyst decays due to masking and poisoning of the catalyst until the catalyst can no longer perform well enough to meet the applicable BACT standard. At that point the catalyst needs to be either washed to increase the activity of the catalyst or replaced. With proper maintenance of both the engine and the three-way catalyst system, the catalyst typically lasts two years, based on continuous operation, before replacement becomes necessary.

The most stringent levels achieved in practice for a lean-burn engine are 0.2 g/bhp-hr (14-17 ppmvd at 15 percent O_2) for NOx and 0.2 g/bhp-hr (25-27 ppmvd at 15 percent O_2) for CO. This determination is for a Waukesha 12VAT27GL lean-burn engine equipped with SCR and oxidation catalyst. The levels achieved in practice are 70 percent lower than the limit established in the preconstruction permit.

d. More Stringent Control Techniques

1. SCONOX

As discussed above, the SCONOX technology has been used for reducing NOx emissions from gas turbines. EmeraChem has adapted the SCONOX technology to reduce NOx emissions from engines. For example, SCONOX was installed on two large natural gas-fueled engine generators at a Texas Instruments facility in Texas. However, the facility closed prior to the commercial operation of the two engines. In addition, EmeraChem is working with Cummins to adapt the SCONOX technology to diesel engines.

In summary, it appears that SCONOX technology could be applied to lean-burn or rich-burn engines. However, the technology has not been used to control the emissions from an engine outside of a laboratory setting. In the application of the technology on gas turbines, there have been technical issues at each of its installations regarding the initial implementation of the technology. Consequently, commercial demonstrations are needed to dispel these concerns. In addition, it is unclear what the overall cost effectiveness of the SCONOX technology is relative to other control techniques used for engines.

e. BACT Recommendations

The most stringent BACT levels achieved in practice for a fossil fuel fired engine is the emission levels currently specified as BACT in the SCAQMD. These emission levels are 0.15 g/bhp-hr (9 ppmvd at 15 percent O_2) for NOx, 0.15 g/bhp-hr (25 ppmvd at 15 percent O_2) for VOC, and 0.6 g/bhp-hr (56 ppmvd at 15 percent O_2) for CO. These emission standards have represented BACT since 1998, and Appendix B has examples of engines satisfying these levels for over four years. In addition, engines varying in size from 86 bhp to 747 bhp engines have been equipped with three-way catalyst to satisfy these emission standards.

The most stringent BACT level for a reciprocating engine was required in the preconstruction permits for NEO California Power LLC (for two locations: Chowchilla and Red Bluff), JST Energy LLC located at Red Bluff, and Aera Energy for engines located in the oil fields of San Joaquin Valley. The determination for NEO California Power and JST Energy was made for lean-burn engines (4,157 bhp Deutz model TBG632V16 and 3,928 bhp Wartsila model 18V220SG) equipped with SCR and oxidation catalyst. BACT levels were specified at 0.07 g/bhp-hr for NOx, 0.15 g/bhp-hr for VOC, and 0.6 g/bhp-hr for CO. The other determination for Area Energy was for a rich-burn engine (either an 800 bhp Superior 8G-825 engine or a 1,478 bhp Waukeshaw 7042 GSI engine) equipped with a three-way catalyst. BACT levels were specified at 0.071 g/bhp-hr for NOx, 0.069 g/bhp-hr for VOC, and 0.6 g/bhp-hr for CO.

Of the lean-burn engines required to meet this stringent BACT level, both the Chowchilla and Red Bluff facilities have begun operating. Source tests for both facilities should be available by late fall, 2001 and the ARB staff expects the 0.07 g/bhp-hr NOx level to be considered achieved in practice for that class and category sometime next year. The lowest emissions achieved in practice are for the 2,113 bhp Waukesha model 8LAT27GL engine located at the SB Linden facility located in New Jersey. The BACT determination limited emissions of the engine to 50 ppmvd at 15 percent O_2 for NOx, 58 ppmvd at 15 percent O_2 for VOC, and 76 ppmvd at 15 percent O_2 for CO. The engine has been in operation since 1997 and emission tests conducted in 1997 indicated NOx emissions at less than 17 ppmvd at 15 percent O_2 and CO less than 27 ppmvd at 15 percent O_2. The equivalent g/bhp-hr is 0.2 for both NOx and CO. VOC emissions were measured with a test method not consistent with methods used in California and therefore, is not included in this analysis. Given that the same emission control technology used at the SB Linden facility will be used for the lean-burn engines used at the NEO California Power and JST Energy facilities, the ARB staff believes it is technically feasible to achieve the levels specified in the preconstruction permits for these facilities. To achieve these more stringent levels, additional catalyst and higher consumption of ammonia/urea will be necessary beyond that required for the SB Linden facility.

For rich-burn engines, most of the recent BACT determinations and all the available emission test information has been for complying with the BACT NOx level of 9 ppmvd at 15 percent O_2 or 0.15 g/bhp-hr. For the engines subject to this level, 60 percent of all engines with test data (See Appendix B) achieved 5 ppmvd at 15 percent O_2 or 0.07 g/bhp-hr emission level for NOx or better. Additionally, 65 percent of the engines achieved 5 ppmvd at 15 percent O_2 or 0.07 g/bhp-hr emission level for NOx or better in the initial compliance test. This level has been achieved for a wide range of engine horsepower sizes. The examples included in Appendix B range from about 80 bhp up to about 750 bhp. In addition, one engine at Los Alamos Energy, a 713 bhp Caterpillar G398TAHC engine has operated with a three-way catalyst since 1997 and over this period, has been below 5 ppmvd at 15 percent O_2 for three years.

The Aera Energy preconstruction permit, as discussed above, specifies the NOx BACT level at 0.071 g/bhp-hr. The same technology would be used to meet the more stringent levels, with the major difference being the use of about 50 percent more catalyst. No additional change to the other equipment, such as the O_2 sensor or air/fuel ratio controller would be required. Additionally, maintenance requirements and the catalyst life are expected to be the same at 0.15 g/bhp-hr or 0.07 g/bhp-hr.

Based upon the above, the ARB staff recommends establishing a BACT level based upon the achieved in practice levels of the SCAQMD requirements for nonemergency engines. As discussed above, the ARB staff believes the 0.07 g/bhp-hr level proposed in the permits for Aera Energy and for NEO California Power is technically achievable. Consequently, district permitting staffs are encouraged to evaluate these BACT levels represented by these projects as part of the technical feasibility portion of the case-by-case BACT determination for electrical generation projects. In addition, once the NEO California Power has demonstrated achievement of the 0.07 g/bhp-hr NOx level, the ARB staff will consider this level to be achieved in practice for its class and category. Finally, an emission limit for PM is recommended. This PM level is consistent with the technology requirements of the ARB diesel risk management guidance.

The following table summarizes the recommended levels for reciprocating engines:

Table IV-4:
Proposed Emission Levels For
Fossil-Fueled Reciprocating Engines

Equipment Category	NOx (g/bhp-hr)	VOC (g/bhp-hr)	CO (g/bhp-hr)	PM (g/bhp-hr)
Fossil-fueled engines	0.15	0.15	0.6	0.02

2. Future Developments

SB 1298 directs the ARB, at the earliest practicable date, to make its BACT determination guidance to the districts equivalent to that of permitted central station power plants in California. In order for all electrical generation technologies to achieve the same emission level as a central station power plant equipped with BACT emission control technologies will need to improve, as will the efficiencies of reciprocating engines.

A number of the engine manufacturers and the DOE are working together on the Advanced Reciprocating Engine Systems (ARES) program. The goals of this program are to create a natural gas powered engine that will be at least 50 percent efficient and will have NOx emissions of 0.1 g/bhp-hr (0.31 lb/MW-hr). The program began in November 2000 and the goal is to have a prototype of an engine meeting these standards by the end of the decade. As discussed previously, the goals for the emission levels proposed for the ARES program have already been exceeded. For example, the engines used in the NEO California Power facility in Chowchilla are subject to a BACT limit for NOx of 0.07 g/bhp-hr. However, where the program will have the most impact is improving the electrical efficiency of reciprocating engine generators. The most efficient engines are large lean-burn reciprocating engines that are about 40 percent efficient. Improving the efficiency of the engine from 40 to 50 percent will decrease the emissions in the Chowchilla project from 0.2 lb/MW-hr to 0.15 lb/MW-hr, which is still three times more emissions than a central power plant equipped with BACT.

In summary, even with a dramatic increase in electrical efficiency, to reach the goal of emissions that are equivalent to central station power plant equipped with BACT, breakthroughs will be needed in emission control systems that can result in near zero emissions.

D. Engines and Turbines Using Waste Gas

Waste gas refers to gases generated at landfills or in the disgestion of solid materials at waste water treatment plants. Both reciprocating engines and gas turbines have been used to generate electricity from waste gas.

The recently promulgated NSPS (40 Code of Federal Regulation 60, subpart Cc and WWW) requires most landfills to collect and destroy the gas produced by the landfill. At a minimum, landfill operators are required to flare the landfill gas. Many landfills have opted to develop energy projects that allow for the generation of electricity while disposing of the gas. Generally, large reciprocating engine generator sets, typically larger than 800 KW, have been used for these applications. In a few cases, gas turbines have been used instead of reciprocating engines.

Wastewater treatment facilities have commonly utilized digester gas in cogeneration facilities. Digester gas can be burned in a reciprocating engine to generate electricity for the facility and the heat generated by the engine can be used for the digestion process. (The ARB staff is aware of only one gas turbine used in this same way.)

1. Current Control Technologies Being Used

a. State Implementation Plan Measures

While there are no SIP control measures specifying reductions from waste gas combustion, many of the SIP measures affecting reciprocating engines or gas turbines have provisions affecting engines used in waste gas applications.

The most stringent of SIP measures for reciprocating engines have been adopted by SCAQMD, AVAPCD, and San Diego County Air Pollution Control District (SDCAPCD). Both measures set emission standards for NOx, VOC, and CO. The SCAQMD and AVAPCD requires reciprocating engines using waste gas to meet the following emission standards: 50-63 ppm at 15 percent O_2 for NOx, 350-440 ppm at 15 percent O_2 for VOC, and 2000 ppm at 15 percent O_2 for CO, with the applicable NOx and VOC standard depending upon the efficiency of the engine. SDCAPCD does not regulate waste gas usage, but requires lean-burn engines to achieve either 65 ppmvd at 15 percent O_2 or 90 percent reduction for NOx.

For gas turbines, the most stringent of these measures has been adopted by SCAQMD and AVAPCD. For the turbines typically used in landfill applications, these measures limit the NOx emissions from 9 to 25 ppmvd at 15 percent O_2, based upon the size and efficiency of the turbine. In addition, a limit of 25 ppmvd applies to turbines between 2.9 and 10 MW that use a fuel with a minimum percentage of 60 percent digester gas.

b. Control Techniques Required As BACT

1. Reciprocating Engines

Waste gas contains impurities that, if combusted will likely poison catalyst based post-combustion control systems. Consequently, the approach for combusting waste gas in either a reciprocating engine or gas turbine has focused on combustion processes that result in minimal NOx being produced and noncatalytic control systems. For reciprocating engines, lean-burn engines have been the choice because these types of engines produce the lowest emission of NOx without using post combustion treatment technologies. In the case of gas turbines, the control techniques used in these applications include either low NOx combustors or water/steam injection to reduce NOx emissions.

For reciprocating engines, the most stringent BACT determination in a preconstruction permit for either landfill or digester gas is for the Riverside Country Waste Management's Badlands facility. The permit established a limit of 0.31 g/bhp-hr for NOx, 0.02 g/bhp-hr for VOC, and 1.49 g/bhp-hr for CO. The determination is for a 1,777 bhp Deutz model TBG620 lean-burn engine using landfill gas. This determination is based upon a vendor guarantee and the engine is not yet installed.

2. Gas Turbines

For gas turbines, the most stringent BACT determination for use of waste gas (with some supplemental natural gas) that has appeared in a preconstruction permit is for the Joint Water Pollution Control Plant in Carson. The permit established a limit of 25 ppmvd at 15 percent O_2 for NOx emissions. The determination is for three Solar Mars 90 (10 MW) combined cycle units generating a total of 34.8 MW. The level is achieved with water injection.

The most stringent BACT determination for waste gas that has appeared in a preconstruction permit is for the University of California, Los Angeles (UCLA) Energy Systems facility. The facility consists of two General Electric LM1600 gas turbines and one common steam turbine. The combined cycle system initially burned a mixture of landfill gas and natural gas in a 30/70 mixture, respectively, based on energy. The amount of landfill gas has declined over time and the current mix is 15/85. Additionally, the landfill gas is treated extensively to remove potential poisons prior to being combusted in the gas turbines. The permit established a limit of 9 ppmvd at 15 percent O_2 for NOx emissions. SCR can be used to achieve this level because of the low percentage of landfill gas and the extensive treatment of the gas mixture prior to combustion in the gas turbine.

c. Emission Levels Achieved In Practice

1. Reciprocating Engines

The most stringent emission levels achieved in practice by reciprocating engines using waste gases are a function of the quality of the waste gas that has been burned (the energy content of the gas and the percentage of CO_2 in the waste gas). In general, the latest engines are able to demonstrated compliance with a BACT level of 0.6 g/bhp-hr for NOx. For landfill gas-fueled engines, the results of the testing varied from 0.31 to 0.48 g/bhp-hr of NOx, which demonstrates the variability of the landfill gas composition and its impact on the engine's NOx emissions. Similar results were seen for engines using digester gas in that the results of the testing varied from 0.36 to 0.52 g/bhp-hr of NOx. For the engines used in landfill applications, the engines tested range from 850 bhp to 4,300 bhp. Similarly, for digester gas fueled engines, the tested engines range from 260 bhp to 1,400 bhp.

For CO and VOC, there have been similar variations in emission levels. Some of this variation can be explained by operators focusing on meeting NOx levels at the expense of CO or VOC emissions. For landfill gas fueled engines, VOC emission levels have varied from 0.05 to 0.32 g/bhp-hr, and for digester gas, VOC emission levels have varied from 0.2 to 0.5 g/bhp-hr. Similarly, for CO emission levels, the emission levels have varied from 1.6 to 3.9 g/bhp-hr for landfill gas and, the emission levels have varied from 1.5 to 2 g/bhp-hr for digester gas.

2. Gas Turbines

For gas turbines using a waste gas, the above mentioned Joint Water Pollution Control Plant achieved between 19 and 22 ppmvd at 15 percent O_2 for NOx levels and 8 to 19 ppmvd at 15 percent O_2 for CO levels.

d. BACT Recommendations

1. Reciprocating Engines

The most stringent BACT determination for a reciprocating engine using a waste gas in a preconstruction permit is 0.31 g/bhp-hr for NOx, 0.02 g/bhp-hr for VOC, and 1.49 g/bhp-hr for CO. This determination is for a Deutz TBG620 lean-burn engine at the Badlands Landfill in Riverside. This level is based upon a vendor guarantee for equipment that has not yet been installed.

The most stringent BACT level achieved in practice for reciprocating engines using waste gas is 0.31 g/bhp-hr for NOx, 0.1 g/bhp-hr for VOC, and 1.59 g/bhp-hr for CO. This determination is for a 4,230 bhp Caterpillar G3616 lean-burn engine, an engine much larger than the Deutz engine, at the Tajiguas Landfill in Santa Barbara. NOx emissions for this same engine at other landfills varied from 0.39 to 0.56 g/bhp-hr indicating the influence of the quality of the landfill gas on NOx emissions.

Based on the levels achieved in practice, the ARB staff recommends the following levels for a reciprocating engine using a waste gas: 0.6 g/bhp-hr for NOx, 0.6 g/bhp-hr for VOC, and 2.5 g/bhp-hr for CO. Individual engines operating with waste gas may perform better than these proposed levels, but these proposed emission levels are achievable for all engines using a waste gas. In addition, these levels are consistent with the SCAQMD's BACT guidance for this category of sources. Finally, the VOC and CO are set at higher levels to allow operators flexibility in combustion modifications to meet stringent NOx levels.

2. Gas Turbines

For gas turbines, the most stringent BACT determination for use of a waste gas that has appeared in a preconstruction permit is for the Joint Water Pollution Control Plant in Carson. The permit established a limit of 25 ppmvd at 15 percent O_2 for NOx emissions for each of three Solar Mars 90 turbines. Subsequent testing indicated this level can be achieved in practice. Additionally, the BACT determination for the UCLA energy project was not considered typical of waste gas applications because of the high percentage of co-fired natural gas.

The ARB staff recommends the BACT level for gas turbines using a waste gas is 25 ppmvd at 15 percent O_2 for NOx emissions.

2. Future Developments

SB 1298 directs the ARB, at the earliest practicable date, to make its BACT determination guidance to the districts equivalent to that of permitted central station power plants in California. In order for all electrical generation technologies to achieve the same emission level as a central station power plant equipped with BACT emission control technologies will need to improve, as will the efficiencies of reciprocating engines.

Because the impurities in waste gas can poison catalysts, options for reducing emissions from waste gas combustion are limited. As discussed above, significant reductions of NOx are only possible with post combustion pollution cleanup systems. Cleanup systems to remove the impurities have been considered, but have either had limited success or have not been cost effective. Consequently, for reciprocating engines, most of the focus in reducing emissions has been based upon improving the emission characteristics of lean-burn engines. In addition, the previously discussed ARES program is applicable in that the goal of developing a 50 percent electricity efficient will improve the emissions of engine burning waste gas on a lb/MW-hr basis.

Similarly, for gas turbines, the most advanced post combustion pollution cleanup systems cannot be used in waste gas applications. Emission reductions will focus on improved combustion techniques such as improving low NOx combustors or demonstrating catalytic combustion technology on waste gas fuels. Low NOx combustors have been developed for larger turbines that can achieve 9 ppmvd at 15 percent O_2.

Overall, this category of using waste gas to generate power will have the most difficulty in attaining the goal of equivalent emissions to a central station power plant equipped with BACT. However, this difficulty should be balanced with the recognition that historically waste gases were either not collected or were flared without controls.

E. Microturbines

Microturbines are an emerging technology generally sized (30 to 75 kW) below the permitting threshold for gas turbines. Consequently, there are no SIP requirements or BACT determinations made for this equipment category.

Beginning in January 1, 2003, emissions from new microturbines will be regulated through the ARB DG certification program. The ARB staff recommends that districts permitting microturbines after January 1, 2003 require the units to be certified by the ARB DG certification program.

F. Fuel Cells

A fuel cell is an electrochemical device that combines hydrogen with oxygen from the air to produce electricity, heat, and water. Some districts have added fuel cells to the list of equipment exempted from district permit requirements. The stationary fuel cell community is currently served by one commercial product, a 200 kW phosphoric acid fuel cell. However, the fuel cell manufacturing community is engaged in a strong commercialization effort with other fuel cell types (e.g., proton exchange membrane, solid oxide, and molten carbonate) and is currently establishing a manufacturing capability to meet an emerging market. Fuel cells themselves do not emit air pollutants, but the reformers used to supply the hydrogen fuel can emit small quantities of pollutants. Source tests conducted on a fuel cell with a reformer indicate that emissions of NOx are about 2 ppmvd at 15 percent O_2 or about 0.06 lb/MW-hr—near the emission level of a central station power plant equipped with BACT. The ARB staff has no additional recommendations regarding BACT requirements for fuel cells.

G. Stirling-Cycle Engines

A Stirling-cycle engine is a closed loop engine where a heat source is provided outside the engine to move a piston. Heat sources used to operate a Stirling-cycle engine can include waste heat, solar energy, and combustion gases. The first commercial electrical generation applications of the Stirling-cycle engine are expected to be available next year. The manufacturer reports that emissions from prototype products have been very low. However, until a commercial product is available, and the emissions evaluated, it is premature for the ARB staff to evaluate BACT requirements for this category.

VI. ACHIEVING CENTRAL STATION POWER PLANT EMISSION LEVELS

SB 1298 directs the ARB, at the earliest practicable date, to make its BACT determination guidance to the districts equivalent to that of permitted central station power plants in California. In order for all electrical generation technologies to achieve equivalent emissions of a central station power plant equipped with BACT, control technologies will need to improve, as will the conversion efficiency from fossil fuel to electrical energy. In addition, as discussed below, the ARB staff is recommending that the achievement of central station power plant levels recognizes the contributions from combined heat and power applications (CHP). It should be noted that the emission levels currently achieved by the various electrical generation technologies discussed in this report has significantly improved from that which was achievable even five years ago.

A. Gas Turbines

For gas turbines rated at 50 MW or less, the same control technologies being used on central station power plants are being used for the smaller gas turbines. However, because of the lower efficiencies of the small turbines, a 5 MW turbine achieving a NOx level of 5 ppmvd at 15 percent O_2 emission level will have a higher lb/MW-hr emission rate than the central station power plant achieving a 5 ppmvd at 15 percent O_2. Consequently, if the efficiencies of the smaller turbines do not improve, achieving the same emission level as central station power plants will require the smaller turbines to achieve significantly greater emissions reductions. To meet the emission level achieved by central station power plants, emission levels approaching 1 ppmvd at 15 percent O_2 will be necessary. The only technology that has the potential to reduce emissions to this level is SCONOX. However, as discussed above, SCONOX is still an emerging technology that has not been demonstrated on the full size range of electrical generation technologies.

In the case of CHP applications, the thermal energy produced and subsequently used is displacing thermal energy that would have likely been provided by a boiler. If the energy represented by the thermal energy is credited toward the electrical generation facility's total energy production, then the emission level (lb/MW-hr) will be near the level of central station power plant equipped with BACT. For example, for a turbine electrical generation facility achieving the proposed NOx emission level of 0.12 lb/MW-hr (3 ppmvd at 15 percent O_2), the thermal energy credit for an efficient CHP application would result in an equivalent emission rate of 0.06 lb/MW-hr. Efficient CHP is defined as CHP applications that achieve a minimum of 60 percent efficiency and 75 percent efficiency on an annual basis. Consequently, CHP applications that achieve a NOx emission level of 3 ppmvd at 15 percent O_2 will have the equivalent emissions of a central station power plant equipped with BACT.

Similarly, for VOC and CO, the central station power plant levels will be very difficult to achieve for turbines based upon technology alone.. The same control technologies used for central station power plants are used on the smaller turbines—oxidation catalysts. In addition, for turbines rated at 12 MW and larger, achieve the same ppmvd levels, 2 ppmvd at 15 percent O_2 for VOC and 6 ppmvd at 15 percent O_2 for CO, as central station power plants. Because of the lesser efficiencies of the smaller turbines, the emissions in lb/MW-hr are higher. However, if an energy credit for CHP is included, turbines controlled to the same concentration levels as central station power plants and used in efficient CHP applications, would emit the equivalent emission levels achieved by central station power plants.

In summary, the ARB staff recommends that districts encourage the development of electrical generation facilities that are also efficient CHP applications versus generation facilities that are electrical generation only or are considered inefficient CHP. Only those gas turbine based electrical generation facilities used in efficient CHP applications and achieving certain emission levels are capable of achieving the equivalent emissions of central station power plants equipped with BACT.

B. Reciprocating Engines

In general, reciprocating engines will have a difficult time achieving the equivalent emissions of a central station power plant. To achieve the central station power plant NOx emission level, 1 ppmvd at 15 percent O_2 or 0.015 g/bhp-hr would have to be achieved, assuming the efficiency of the engine does not change. This would represent an additional 90 percent reduction from the lowest emission level achieved in practice.

As discussed earlier, one of the major goals of the ARES program is to increase engine efficiencies to 50 percent, which is a significant improvement. This would decrease the emissions in the Chowchilla project from 0.2 lb/MW-hr to 0.15 lb/MW-hr, which is still three times more emissions than a central power plant equipped with BACT. The Chowchilla project is using engines that are very efficient for a reciprocating engine, achieving an efficiency of about 40 percent. These levels can only be achieved by the largest lean-burn reciprocating engines--the efficiencies of smaller engines is closer to 30 percent. In addition, the Chowchilla engines are expected to achieve 0.07 g/bhp-hr NOx level--the cleanest engines installed in California.

If an energy credit for CHP is included, the engine achieving the proposed NOx emission level of 0.2 lb/MW-hr would be equivalent to 0.1 lb/MW-hr. Consequently, engines units used in CHP applications could achieve the equivalent NOx emissions of a central station power plant equipped with BACT if the benefits of CHP is included and compared to the levels already achieved, there is either a 30 percent reduction in emission or an equivalent increase in electrical efficiency.

For the other pollutants, VOC and CO, the current levels achieved in practice are substantial higher than central station power plant levels. For example, the proposed CO level of 1.9 lb/MW-hr is based upon 90 percent control of CO emissions. An additional 95 percent reduction would be necessary to achieve the central station power plant levels of 0.09 lb/MW-hr. Similarly, for VOC, an additional 95 percent reduction would be necessary to achieve the central station power plant levels of 0.02 lb/MW-hr. Consequently, consideration of the benefits of efficient CHP will lower the overall lb/MW-hr levels, but not to the equivalent emissions of a central station power plant equipped with BACT.

In summary, the ARB staff recommends that districts encourage the development of electrical generation facilities that are used in efficient CHP applications versus generation facilities that are electrical generation only or are considered inefficient CHP. Reciprocating engine based electrical generation satisfying BACT requirements and used in efficient CHP applications will have less environmental impact than electrical generation only applications or inefficient CHP applications.

C. Waste Gas

Neither reciprocating engines nor gas turbines using waste gas as a fuel are likely to achieve the emission levels for central station power plants. Because waste gas contains impurities that, if combusted, will likely poison post-combustion control systems that are based upon catalysts, the emissions from this category cannot be reduced to the same levels that have been achieved with engines and turbines using natural gas as a fuel. Without advance post-combustion control systems, engines and turbines using waste gas will not be able to achieve the equivalent emission levels for central station power plants.

Finally, CHP applications involving waste gas is common only at waste water treatment facilities. At waste waster treatment facilities, there is a need for both process steam and electricity. Consequently, encouraging CHP applications is not likely to result in significant increases of CHP applications.

D. Recommendations

The ARB staff recommend that districts grant credit to electrical generation that are used in efficient CHP applications and the credit would only be used toward satisfying the goal that emissions from distributed generation, at the earliest practicable date, be equivalent to emission levels for central station power plants equipped with BACT. Procedures for determining the CHP credit are discussed in the next Section.

The ARB staff further recommend that, to the extend possible, districts encourage electrical generation projects that are also efficient CHP applications. As discussed above, only efficient CHP electrical generation projects are likely to achieve the equivalent emissions of central station power plants equipped with BACT. This can be achieved by requiring fossil fuel based electrical generation facilities, after applying the CHP credit, to achieve the equivalent emissions of central station power plants equipped with BACT by 2007. As discussed above, gas turbine based electrical generation facilities that achieve emission levels of 3 ppmvd at 15 percent O_2 for NOx, 2 ppmvd at 15 percent O_2 for VOC, and 6 ppmvd at 15 percent O_2 for CO and are efficient CHP applications will have the equivalent emissions of a central station power plant equipped with BACT. For reciprocating engine-based electrical generation, even with the CHP energy credit, achieving this level will depend upon improvements in engine efficiency and improvements in the control technology for reducing CO and VOC emissions. Staff will review the feasibility of achieving central station power plant levels as part of the 2005 technology review that is proposed for the ARB's DG certification program.

Finally, as discussed above, based upon the technology available today, waste gas-based electrical generation is unlikely to achieve the equivalent emission levels for central station power plants. However, the inability to achieve central station power plant levels should be balanced with the understanding that waste gas is typically flared. While there are additional emissions associated with using waste gas in an electrical generation project as compared to the emissions from flaring the waste gas, the value from the energy produced offsets the emissions impacts. In addition, to the extent possible, waste gas based electrical generation should also incorporate CHP.

VII. OTHER PERMITTING CONSIDERATIONS

Much of the guidance provided in the 1999 ARB Power Plant Guidance regarding emissions offsets, ambient air quality impact analysis, and health risk assessment is still applicable. This section provides specific guidance related to distributed generation.

A. Applicability

Microturbines and small reciprocating engines are typically below permitting thresholds for many districts. In some cases, several of these units can be used at one site and the number of units operating at any moment would depend upon the needs of the facility. The ARB staff recommends that districts, that do not already do so, consider modifying their permitting regulations such that the emissions from all the units are treated collectively as opposed to considering the applicability on a unit by unit basis.

B. Combined Heat and Power

For efficient CHP applications, the ARB staff supports allowing credit for process heat that can be use toward meeting the central station power plant emission level. Because CHP applications improve energy efficiency, emissions of greenhouse gases are also reduced.

Typical electrical efficiency of the various technologies addressed by this report range from about 20 percent for microturbines (based on output of electrical generation versus the energy represented by the fuel consumed by the technology) to about 40 percent for larger gas turbines and lean-burn engines. CHP applications can increase efficiency of energy conversion to over 80 percent.

For CHP applications that maintain a minimum efficiency of 60 percent and an annual average efficiency of 75 percent in the conversion of the energy in the fossil fuel to electricity and process heat, the ARB staff recommends that the process heat used be credited as energy production. (The efficiency determination would exclude startup, shutdown, and the facility is shutdown.) That is, the facility's overall lb/MW-hr can be determined by dividing the emissions of the facility, on a pollutant-by-pollutant basis, by the facility's total energy production. The total energy production is the sum of the net electrical production, in MW, and the actual process heat consumed in a useful manner, converted to MW. A more detailed methodology for calculating this credit is provided in Appendix D.

C. Health Risk Assessment Requirements

The 1999 ARB Power Plant Guidance provided a summary of the information that should be addressed by a health risk assessment (HRA) and identified some of the documents that should be consulted in the preparation of a HRA. In addition, for most generating resources covered by this guidance, the ARB staff recommends that the district make permitting decisions consistent with the ARB report: Risk Management Guidelines for New and Modified Sources of Toxics Air Pollutants, July 1993. In the case where diesel-fueled engines are used for emergency electrical generation, the ARB staff recommends that district's permitting decisions be consistent with the ARB report: Diesel Risk Management Guidelines, October 2000.

D. Suggested Permit Conditions

The 1999 ARB Power Plant Guidance provided a number of recommendations to assure compliance with an air permit. This guidance provides further recommendations regarding source testing and monitoring. In addition, sample permit conditions for emission testing and monitoring are contained in Appendix E.

1. Source Testing and Emissions Monitoring

As stated in the 1999 ARB Power Plant Guidance Report, source testing and monitoring requirements need to be established within the permit to assure compliance with the BACT determinations and other applicable emission standards that are established through the district's NSR program. Compliance with BACT levels and other emission standards are demonstrated by either CEM or periodic source testing. In the case of source testing, districts have typically required an initial compliance test to demonstrate compliance with the requirements of the preconstruction permit and periodic tests are required thereafter.

a. Commissioning Period

Prior to the initial source test, the operation of the prime mover and the add-on control equipment undergo commissioning during which the prime mover is tuned and the add-on control equipment is installed and calibrated. The ARB staff recommends that an applicant be required to submit a plan for this activity during the commissioning period. The goal of the plan is to determine the conditions for operation of both the prime mover and the add-on control equipment that minimizes the emissions of air contaminants. For example, for a gas turbine equipped with low NOx combustors and SCR and oxidation catalyst, commissioning activity could include tuning of the low NOx combustor, optimizing both the SCR and oxidation catalyst systems, and calibrating and implementing the CEM. The plan would indicate the procedure the operator will follow to complete the goals of optimizing the performance of each of these components.

Emissions during the commissioning period may be higher than allowed by the permit during normal operation because the emission control equipment is not fully installed and/or not operated at full efficiency. Consequently, to minimize emissions during the commissioning period, the ARB staff recommends: permits limit the time period for commissioning activities; and emissions released during commissioning be counted toward the facility's annual emission limits.

Because of the potential impact and the importance of the activities occurring during the commissioning period, the ARB staff recommends that for major projects, particularly those involving the larger gas turbines, the requirements related to the commissioning period should be spelled out as conditions to the permit. For smaller projects where the impacts are not as significant, issues related to the commissioning period could best be handled through the district's variance process.

b. Continuous Emission Monitors

In general, all but the smallest gas turbines have typically been subject to both CEM and annual source testing. For the Genxon Power Systems facility, where the power is generated by a 1.5 MW Kawasaki gas turbine, CEMs were not required. As discussed in the next section, the BAAQMD allowed the use of periodic monitoring in lieu of both the CEM and annual source testing.

In contrast, reciprocating engines have typically only been subject to periodic source testing. Depending upon the district, an operator of an engine is required to have independent emission testing performed every one to three years. Because of the cost to the project proponent, few districts have required CEM for engines. Only the SCAQMD has required, per Rule 1110.2, Emissions from gaseous and liquid fueled internal combustion engines, engines rated at 1,000 hp or more and operated more than two million bhp-hr per calendar year to be equipped with CEM for NOx. (For example, a 1,000 hp engine would be required to be equipped with a CEM if the engine operated more than 2,000 hours.) Otherwise, some large engines have been required to use CEM through a preconstruction review.

The ARB staff recommends that a CEM, which meets the requirements of 40 CFR Part 60, be required to monitor continuous compliance with emission limits for: 1) all gas turbines larger than 2.9 MW (for NOx, CO and VOC); and 2) engines rated at 1,000 hp or more and operated more than two million bhp-hr per calendar year (for NOx). These recommendations are consistent with SCAQMD's CEM requirements for these source categories. In addition to reporting measurement results in terms of ppmvd at 15 percent O_2 and pound/hour, the CEM results should also be reported in terms of lb/MW-hr.

c. Annual Emissions Testing

After the initial source test, periodic tests are necessary to demonstrate compliance with the emission standards. For facilities equipped with CEM, the ARB staff supports initially requiring tests annually until the district is satisfied that emissions have stabilized. Upon reaching this stable condition, emission testing can then be required at two to three year intervals.

As discussed above, most engines and the smallest gas turbines are not equipped with CEMs. Many districts subject reciprocating engines to annual source tests. In addition, both Santa Barbara County Air Pollution Control District and the SJVUAPCD have also required used of portable analyzers by the operator to periodically monitor emissions of the engine between each source test. The analyzers are used as a screening tool to monitor the effectiveness of the catalyst. As discussed above, because the catalyst loses efficiency over time the use of an analyzer would assist the operator in determining when the catalyst needs servicing or replacement and therefore limit potential exceedances of an emission standard.

As mentioned above, the operator of the Kawasaki gas turbine (1.5 MW) at the Genxon Power Systems facility, was periodically allowed to measure NOx, VOC, and CO emissions in lieu of either installing a CEM or annual source tests. The monitoring requirement is satisfied by weekly periodic measurement of three consecutive hours.

Because of the nature of the emission control technologies being used to reduce emissions from electrical generation technologies, periodic monitoring is an important aspect to ensuring compliance with BACT emission levels. The ARB staff recommends that periodic monitoring be combined with a periodic source test requirement. Periodic monitoring would involve using portable analyzers on at least a quarterly basis to ensure NOx emissions are below permit limits. In conjunction with the periodic monitoring, source test should be required every two to three years.

In addition, for small engines less than 100 bhp, where the cost of annual source test is not cost effective relative to the cost of the engine, the ARB staff recommends quarterly monitoring with portable analyzers be sufficient for the purposes of monitoring emissions. Annual or periodic source test should not be required for small engines, although the district would have the ability to request a source test.

d. Field Enforcement

As discussed above, BACT levels for reciprocating engines have historically been expressed in terms of g/bhp-hr. Standards expressed in terms of g/bhp-hr are difficult to enforce because of the difficulty and uncertainty in measuring brake horsepower. Consequently, some districts have moved to expressing BACT levels for reciprocating engines in concentration or an equivalent ppmvd at 15 percent O_2 and in lb/hr. The ARB staff supports adding additional provisions to the permit that allow for enforceable BACT limits. In the case of reciprocating engines, permit conditions could express BACT levels in equivalent ppmvd at 15 percent O_2 as well as in lb/MW-hr.

2. Equipment Monitoring and Recordkeeping

Because the emission control equipment used to meet the proposed BACT levels must operate at very high efficiencies, guidance is provided here regarding monitoring to ensure that the emission control equipment is operating properly. The ARB staff recommends that, on a weekly basis, certain parameters be observed and recorded in a log--typically the same parameters that were identified during the commissioning period as important for minimizing emissions. These parameters include, but are not limited to: temperature at the inlet and outlet of the catalyst bed; for SCR, injection rate of reducing reagent; and O2 concentration. In addition, the operator should ensure that the parameters are within the range of optimum performance and if the value is outside this range, the log should identify the steps the operator took to correct the problem. Finally, because maintenance plays a strong role in the long-term effectiveness of any add-on control system, the ARB staff recommends that the operator should be required to maintain a log of all maintenance done for the generating unit, as well as the air pollution control system.

E. Permitting of Equipment Exempted From Permit

On occasion, districts are requested to permit a source that is exempted by regulation from district permitting requirements. Applicants do so for a variety of reasons, typically to officially preserve its legal grandfathering rights.

Beginning January 1, 2003, the ARB distributed generation certification will subject electrical generation sources not subject to district permitting requirements to certain requirements. Consequently, the ARB staff recommends that if districts issue permits, after the above date, to electrical generation sources that are not subject to permitting requirements by regulations, that the permit be conditions to meet the same requirements as if the generating source was subject to the ARB distributed generation certification program.

VIII. PERMIT STREAMLINING

A. District Programs

Both the BAAQMD and SCAMQD offer programs to allow manufacturers to certify equipment as meeting all the applicable air quality requirements of that respective district. Because the precertification is equipment specific, the manufacturer would need to demonstrate that the equipment would satisfy the district's BACT requirements and permit conditions. Once this equipment has been pre-approved as meeting district requirements, permits can be issued more expeditiously than the standard permit process. In the case of the SCAQMD program, the permit fees are also significantly reduced.

Several districts have programs for expedited permit issuance. These programs are available for select source categories and are intended for small emission units or temporary activities such as gas stations, dry cleaning machines, and contaminated soil cleanup. The source categories covered must meet certain emission standards.

The SCAQMD offers streamlined standard permits. This program is only available for lithographic printers, replacement dry cleaners, and soil excavation plans. For these three sources, total facility emissions must also be less than four tons per year and the facility cannot be next to a school. Finally, the equipment must meet all the requirements shown in the streamlined standard permit application.

B. ARB's Distributed Generation Certification Program

As required by SB 1298, ARB is required to develop and implement a certification program for generating technologies that are not subject to district permitting requirements. To obtain state certification, the generating technology must satisfy certain requirements, including emission standards for NOx, VOC, PM, and CO. This program will only be available for electrical generation technologies that are not subject to permitting requirements in any of the 35 local districts. For electrical generation technologies not otherwise subject to the DG certification program, the ARB's Equipment and Process Precertification Program is the vehicle for manufacturers seeking to validate emission claims. For details regarding the ARB's DG certification program, see the ARB staff report: Initial Statement of Reasons for the Proposed Regulation to Establish a Distributed Generation Certification Program, September 2001.

C. Recommendations

The district precertification programs discussed above are designed for small simple sources or sources that have minimal air quality impact. Electrical generation equipment does not fit this profile in that emissions impacts can be significant, the offset provisions of district NSR programs may be triggered, and a number of site specific issues may have to be addressed. Each electrical generation facility proposal tends to be unique and has to be evaluated against its own merits. Consequently, precertification or accelerated review programs are typically not appropriate for the permitting of electrical generation.

ARB staff encourages districts to review their permitting programs and look at areas in the permitting process for electrical generation equipment that can be streamlined. For example, elements that could be streamlined include standardized permit applications, precertified emission rates for standardized products (however, a source test would still be required to convert the Authority to Construct to a Permit to Operate), rapid decisions on BACT, and standardized permit conditions.

Finally, the threshold for permits varies greatly between the local districts. For example, permit thresholds for reciprocating engines vary from engines larger than 50 bhp to exempting from permitting requirements all engines fueled with natural gas. Districts should make information regarding exemption levels easily accessible (i.e., on a website) to interested parties. To the extent that uniform permit thresholds would simplify both the certification and permitting process for electrical generation equipment, the ARB staff encourages districts to revise permitting thresholds affecting electrical generation units.

IX. REFERENCES

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Appendices

Appendix A:

California Senate Bill 1298 (Bowen and Peace)

BILL NUMBER: SB 1298
CHAPTERED BILL TEXT

CHAPTER 741	
FILED WITH SECRETARY OF STATE	SEPTEMBER 27, 2000
APPROVED BY GOVERNOR	SEPTEMBER 25, 2000
PASSED THE SENATE	AUGUST 31, 2000
PASSED THE ASSEMBLY	AUGUST 29, 2000
AMENDED IN ASSEMBLY	AUGUST 25, 2000
AMENDED IN ASSEMBLY	AUGUST 18, 2000
AMENDED IN ASSEMBLY	AUGUST 7, 2000
AMENDED IN ASSEMBLY	JUNE 26, 2000
AMENDED IN SENATE	MAY 28, 1999
AMENDED IN SENATE	APRIL 5, 1999

INTRODUCED BY Senators Bowen and Peace

MARCH 1, 1999

An act to add Sections 41514.9 and 41514.10 to the Health and Safety Code, relating to air pollution.

LEGISLATIVE COUNSEL'S DIGEST

SB 1298, Bowen. Air emissions: distributed generation.

(1) Existing law requires the State Air Resources Board to consider and adopt specified findings before adopting rules or regulations that would affect the operation of existing powerplants. Under existing law, except as specified, any person who violates any statute, rule, regulation, permit, or order of the state board or of an air pollution control strict or an air quality management district relating to air quality, as provided, is guilty of a misdemeanor and is subject to a fine, imprisonment, or both.

This bill would require the state board, on or before January 1, 2003, to adopt a certification program and uniform emission standards for electrical generation that are exempt from district permitting requirements, and would require that those standards reflect the best performance achieved in practice by existing electrical generation technologies.

The bill would require the state board, on or before January 3, 2003, to issue guidance to districts on the permitting or certification of electrical generation technologies under their regulatory jurisdiction, as prescribed.

Since a violation of the regulations adopted pursuant to the bill would be a crime, the bill would impose a state-mandated local program.

(2) The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for a specified reason.

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1. The Legislature finds and declares all of the following:

(a) Distributed generation can contribute to helping California meet the energy requirements of its citizens and businesses.

(b) Certain distributed generation technologies can create significant air emissions.

(c) A clear set of rules and regulations regarding the air quality impacts of distributed generation will facilitate the deployment of distributed generation.

(d) The absence of clear rules and regulations creates uncertainty that may hinder the deployment of distributed generation.

(e) It is in the public interest to encourage the deployment of distributed generation technology in a way that has a positive effect on air quality.

(f) It is the intent of the Legislature to create a streamlined and seamless regulatory program, whereby each distributed generation unit is either certified by the State Air Resources Board for use or subject to the permitting authority of a district.

SEC. 2. Section 41514.9 is added to the Health and Safety Code, to read:

41514.9. (a) On or before January 1, 2003, the state board shall adopt a certification program and uniform emission standards for electrical generation technologies that are exempt from district permitting requirements.

(b) The emission standards for electrical generation technologies shall reflect the best performance achieved in practice by existing electrical generation technologies for the electrical generation technologies referenced in subdivision (a) and, by the earliest practicable date, shall be made equivalent to the level determined by the state board to be the best available control technology for permitted central station powerplants in California. The emission standards for state certified electrical generation technology shall be expressed in pounds per megawatt hour to reflect the expected actual emissions per unit of electricity and heat provided to the consumer from each permitted central powerplant as compared to each state certified electrical generation technology.

(c) Commencing on January 1, 2003, all electrical generation technologies shall be certified by the state board or permitted by a district prior to use or operation in the state. This section does not preclude a district from establishing more stringent emission standards for electrical generation technologies than those adopted by the state board.

(d) The state board may establish a schedule of fees for purposes of this section to be assessed on persons seeking certification as a distributed generator. The fees charged, in the aggregate, shall not exceed the reasonable cost to the state board of administering the certification program.

(e) As used in this section, the following definitions shall apply:

(1) "Best available control technology" has the same meaning as defined in Section 40405.

(2) "Distributed generation" means electric generation located near the place of use.

SEC. 3. Section 41514.10 is added to the Health and Safety Code, to read:

41514.10. On or before January 1, 2003, the state board shall issue guidance to districts on the permitting or certification of electrical generation technologies under the districts regulatory jurisdiction. The guidance shall address best available control technology determinations, as defined by Section 40405, for electrical generation technologies and, by the earliest practicable date, shall make those equivalent to the level determined by the state board to be the best available control technology for permitted central station powerplants in California. The guidance shall also address methods for streamlining the permitting and approval of electrical generation units, including the potential for precertification of one or more types of electrical generation technologies.

SEC. 4. No reimbursement is required by this act pursuant to Section 6 of Article XIIIB of the California Constitution because the only costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIIIB of the California Constitution.

Appendix B
Supporting Material for BACT Review For Electrical Generation Technologies

I. INTRODUCTION

Discussed in detail below are recommended emission levels for electrical generation sources using small gas turbines (less than 50 MW in size), reciprocating engines using fossil fuel, and gas turbines / reciprocating engines using waste gas. The discussion below is based upon the requirements for determining Best Available Control Technology (BACT) in California and that BACT in California is equivalent to federal requirements for lowest achievable emission rate (LAER). BACT is generally specified as the most stringent emission level of these three alternative minimum requirements: 1) the most stringent emission control contained in any approved State Implementation Plan (SIP); 2) the most effective control achieved in practice; and 3) the most efficient emission control technique found by the district to be both technologically feasible and cost effective.

This appendix provides the basis for the information presented in Chapter V (BACT for Electrical Generation Technologies). This appendix addresses BACT determinations for oxides of nitrogen (NOx), volatile organic compounds (VOC), carbon monoxide (CO), and particulate matter (PM).

For the most effective control achieved in practice, examples were provided of BACT determinations in preconstruction permits issued by California districts and other states, and the most stringent emission levels achieved in practice. For each example cited, the following information is included: the name of the facility the equipment is located at, the applicable California district or State making the BACT determination, a description of the basic equipment, and the method of control used to reduce emissions. In addition, for the control techniques required as BACT in a preconstruction permit, the status of the permit (authority to construct/permit to construct or permit to operate) and the BACT levels established by the permitting agency are provided. Similarly, for emission levels achieved in practice, the date the emission test was conducted and the measured emission levels are provided. The emissions testing was conducted with Air Resources Board (ARB) or United States Environmental Protection Agency (U.S. EPA) approved test methods.

Information was obtained primarily from California district rules, personal contacts with California and out-of-state regulatory agency staff, vendors of basic equipment, and control technology vendors. Additional important sources of information were guidelines for BACT from the following districts, available on the applicable district's website: Bay Area Air Quality Management District (BAAQMD), San Diego County Air Pollution Control District (SDCAPCD), and the South Coast Air Quality Management District (SCAQMD). Finally, BACT determinations listed in the California Air Pollution Control Officers Association (CAPCOA) BACT Clearinghouse, San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) Clearinghouse, and the U. S. EPA Reasonably Available Control Technology (RACT)/BACT/LAER Clearinghouse were reviewed.

Based upon the information collected for the most stringent emission control contained in any approved SIP and the most effective control achieved in practice, a recommended emission level is provided. These recommendations serve as a starting point for districts to make case-by-case BACT determinations. As discussed below, there are additional emission control technologies that the ARB staff believes are technologically feasible, and district staff should consider these technologies in BACT determinations for electrical generation technologies.

II. GAS TURBINES LESS THAN 50 MW

A. Control Technologies

Many of the control techniques applicable to small gas turbines have been described in the ARB report: Guidance for Power Plant Siting and Best Available Control Technology, September 1999 (referred to as the "ARB Power Plant Guidance" in the rest of this appendix). Refer to this report for a detailed description of the control technologies discussed below.

B. Current SIP Control Measures

There are several SIP control measures specifying reductions in NOx emissions from gas turbines. The most stringent of these measures has been adopted by the SCAQMD and the Antelope Valley Air Pollution Control District (AVAPCD) with NOx emission standards based upon size, annual operating hours, and control system used. The SCAQMD and AVAPCD requirements vary from 25 ppm for the smallest turbines (rating from 0.3 to under 2.9 MW) to 9 ppm for turbines larger than 2.9 MW.

C. Control Techniques Required As BACT

1. BACT Guidelines

To assist applicants in meeting BACT requirements, the BAAQMD, SDCAPCD, and SCAQMD have published BACT guidelines. For gas turbines, both BAAQMD and SCAQMD have separate BACT levels for small gas turbines (rated at less than 3 MW in the SCAQMD and rated at less than 2 MW in BAAQMD) and for larger gas turbines (rated at 3 MW and larger up to 50 MW). For the small gas turbines, both the BAAQMD and SCAQMD guidance specify 9 ppmvd at 15 percent

O_2 for NOx (BAAQMD Guidelines also identify as technically feasible and cost effective a 5 ppmvd at 15 percent O_2 for NOx based upon the application of catalytic combustion or high temperature SCR system with combustion modifications). In addition, the SCAQMD guidance specifies 10 ppmvd at 15 percent O_2 for CO. For larger turbines, the most stringent requirements specified in these guidelines are 5 ppmvd at 15 percent O_2 for NOx, 2 ppmvd at 15 percent O_2 for VOC, and 6 ppmvd at 15 percent O_2 for CO. These emission levels are consistent with the 1999 ARB Power Plant Guidance for simple cycle gas turbines larger than 50 MW.

2. BACT Determinations

Table B-1 lists examples of the most stringent emission controls required as BACT, by California districts or other states, for emissions of NOx, VOC, CO, and if applicable, ammonia from 19 gas turbine based electrical generation facilities.

The gas turbines used in these facilities range in size from the Kawasaki turbine that can generate up to 1.5 MW to a General Electric LM5000 turbine generating up to 49 MW. All of these facilities use natural gas as the primary fuel, although a few facilities are allowed to use an alternative liquid fuel. Many of these facilities have combined heat and power (CHP) applications (identified in the description of basic equipment by the inclusion of a heat recovery steam generator). The Cal Tech facility is the only combined-cycle power configuration listed in Table B-1.

NOx control methods include techniques that minimize emissions and post combustion technologies. The techniques that minimize emissions include XONON (a catalytic combustion technology that can achieve levels reached by post combustion systems), low NOx combustors, and water/steam injection. Post combustion systems such as selective catalytic reduction (SCR) and SCONOX have been used to achieve the lowest emission levels required by recent BACT determinations. Typically, BACT levels are satisfied with a combination of these technologies. Overall, SCR is the most common technology used to satisfy BACT levels, and it has been proposed to satisfy BACT for a turbine as small as a 3.5 MW Solar Centaur 40. As discussed below, both the XONON and SCONOX technology have been used on a more limited basis.

Oxidation catalyst has been the control device of choice to reduce the emissions of both VOC and CO from gas turbines. The list of recent BACT determination indicates that oxidation catalyst has been required for all but the smallest electrical generation resources. In addition, one of the advantages of the SCONOX and XONON technologies is its ability to reduce emissions of VOC and CO in addition to NOx.

A review of the BACT determinations for NOx shown in Table B-1 indicate that BACT determinations are more stringent for gas turbines that generate more

Table B-1
Emission Control Requirements for Combustion Turbine Electrical Generation Less Than 50 MW

Facility Name	District / State	Description of Basic Equipment	Method of control	Permit Status	BACT Level (ppmvd @ 15%O2) One hour average			
					NOX	VOC	CO	NH3
Alliance Colton--Century	SCAQMD	(4) 10.5 MW General Electric 10B1 (116 MMBtu/hr) generating total of 40 MW	XONON or selective catalytic reduction (SCR)/CO oxidation catalyst	PTC 3/01	5	2	6	5 if SCR
Alliance Colton--Drews	SCAQMD	(4) 10.5 MW General Electric 10B1 (116 MMBtu/hr) generating total of 40 MW	XONON or SCR/CO oxidation catalyst	PTC 3/01	5	2	6	5 if SCR
B. Braun Medical (previously McGraw) -- Irvine	SCAQMD	Solar Centaur T-4701 (3.3 MW and 44.6 MMBtu/hr) and GS-4000 (2.8 MW and 42 MMBtu/hr) with heat recovery steam generator equipped with duct burner and generating a total of 6 MW	Water injection / SCR / oxidation catalyst	PTC 9/93	9**	NA	10**	10**
California Institute of Technology, Pasadena	SCAQMD	Solar Centaur 50-TS900 generating 4.2 MW (58.9 MMBtu/hr) with heat recovery steam generator and steam turbine for total of 5 MW	Water injection / SCR	PTC 9/96	9	lb/hr limits	lb/hr limits	20
CalPeak Power--Buttonwillow	SJVUAPCD	(2) 24.7 MW Pratt & Whitney FT-8 Twin Pac (246 MMBtu/hr) generating total of 49 MW	DLN combustors / SCR / oxidation catalyst	ATC 4/01	3.4*	2*	NA	10

Table B-1
Emission Control Requirements for Combustion Turbine Electrical Generation Less Than 50 MW

Facility Name	District / State	Description of Basic Equipment	Method of control	Permit Status	BACT Level (ppmvd @ 15%O2) One hour average			
					NOX	VOC	CO	NH3
CalPeak Power--Panoche	SJVUAPCD	(2) 24.7 MW Pratt & Whitney FT-8 Twin Pac (246 MMBtu/hr) generating total of 49 MW	Dry Low NOx (DLN) combustors / SCR / oxidation catalyst	ATC 4/01	3.4*	2*	NA	10
Double C Limited--Oilfield	SJVUAPCD	General Electric LM2500 gas turbine (222 MMBtu/hr) with heat recovery steam generator producing 24 MW	Steam injection / SCR / oxidation catalyst	PTO 7/98	4.5 *	NA	51*	20
Genetics Institute--Andover, Massachusetts	Massachusetts	Solar Taurus 60 generating 5 MW (65 MMBtu/hr) with heat recovery steam generator equipped with duct burner	DLN combustors / SCONOX	ATC 9/98	2.5 NG / 15 oil	NA	5	NA
Genxon Power Systems--Santa Clara	BAAQMD	Kawasaki M1A-13 with Xonon generating 1.5 MW (22.9 MMBtu/hr)	XONON	PTO 4/99	5*	5*	10*	NA
High Sierra Limited--Oilfield	SJVUAPCD	General Electric LM2500 gas turbine (222 MMBtu/hr) with heat recovery steam generator producing 25 MW	Steam injection / SCR / oxidation catalyst	PTO 6/98	4.5	NA	51	20
LADWP--Valley	SCAQMD	General Electric LM6000 enhanced Sprint gas turbine (466 MMBtu/hr) generating 47.4 MW	Water/steam injection-SCR and oxidation catalyst	ATC 5/01	5	2	6	5

Table B-1
Emission Control Requirements for Combustion Turbine Electrical Generation Less Than 50 MW

Facility Name	District / State	Description of Basic Equipment	Method of control	Permit Status	BACT Level (ppmvd @ 15%O2) One hour average			
					NOX	VOC	CO	NH3
Live Oak Limited--Oilfield	SJVUAPCD	General Electric LM5000 gas turbine (460 MMBtu/hr) with heat recovery steam generator producing 49 MW	Steam injection / SCR / oxidation catalyst	ATC 99	3.6*	0.6	11*	20
Northern California Power--Lodi	SJVUAPCD	General Electric LM5000 gas turbine (460 MMBtu/hr) producing 49 MW	Steam injection / SCR / oxidation catalyst	ATC 3/99	3*	none	200*	25
NRG Energy Center Round Mountain, LLC--Oilfield	SJVUAPCD	General Electric LM6000 enhanced Sprint gas turbine (466 MMBtu/hr) with heat recovery steam generator equipped with duct burner generating 47.4 MW	Water/steam injection-SCR and oxidation catalyst	ATC 4/01	2*; 2.5**	2	lb/hr limit	5
Redding Power--Redding	Shasta Co. APCD	Alstom GTX 100 (407 MMBtu/hr) with heat recovery steam generator producing 43 MW	SCONOX	ATC 3/01	2.5	1.4	6	NA
Saint Agnes Medical Center--Fresno	SJVUAPCD	(2) Solar Centaur 40 generating 3.5 MW (58.9 MMBtu/hr) producing a total of 7 MW	DLN combustors / SCR	ATC 2/00	5	6	50	10
San Joaquin Cogen--Lathrop	SJVUAPCD	General Electric LM5000 gas turbine (460 MMBtu/hr) with heat recovery steam generator producing 48.6 MW	Steam injection / SCR / oxidation catalyst	ATC 99	3.8**	NA	12**	20

Table B-1
Emission Control Requirements for Combustion Turbine Electrical Generation Less Than 50 MW

Facility Name	District / State	Description of Basic Equipment	Method of control	Permit Status	BACT Level (ppmvd @ 15%O2) One hour average			
					NOX	VOC	CO	NH3
University of California, San Diego	San Diego Co. APCD	(2) Solar Titan generating 12.9 MW (148.6 MMBtu/hr) for total of 25 MW	SoLoNox / SCONOX	ATC 1/01	2.5	NA	5	NA
University of California, San Francisco	BAAQMD	(2) Solar Taurus 60 generating 5 MW (76 MMBtu/hr) with heat recovery steam generator equipped with duct burner for total of 10 MW	SCR /oxidation catalyst	PTO 1998	5 NG / 8 oil*	0.01 lb/MMBtu	10*	10

* 3-hr average
** 15 minute rolling average

than 10.5 MW. Recent BACT determinations have required combustion turbines larger than 10.5 MW to achieve NOx ppmvd levels ranging from 2 to 4.5 ppm at 15 percent O_2 or better, based on averaging periods of up to a three-hour rolling average. The most stringent BACT level required in a preconstruction permit is for the NRG Energy Center Round Mountain facility located in the San Joaquin Valley. The BACT determination was 2 ppmvd at 15 percent O_2 for NOx averaged over three hours. Ammonia slip for this facility was set at 5 ppmvd at 15 percent O_2. The determination is for a General Electric LM6000 enhanced sprint gas turbine with a heat recovery steam generator and equipped with water or steam injection, SCR, and oxidation catalyst. In addition, Northern California Power in Lodi was permitted at 3 ppmvd at 15 percent O_2 averaged over three hours for NOx. The facility consists of a General Electric LM5000 gas turbine operated in a simple-cycle mode and equipped with steam injection, SCR, and oxidation catalyst.

Conversely, except when SCONOX is specified as the NOx emission control system, smaller units have been required to achieve 5 ppm at 15 percent O_2. Several facilities have been permitted at this level. These include the Saint Agnes Medical Center, the University of California, San Francisco (UCSF) and two projects for Alliance Colton. The Saint Agnes Medical Center generating facility consists of a Solar Centaur 40 (3.5 MW) equipped with dry low NOx combustors and SCR. The unit at UCSF uses a Solar Taurus 60 (5 MW) with heat recovery and is equipped with water injection and SCR. Finally, the Alliance Colton facilities are based upon a General Electric 10B1 (10 MW) operated in simple cycle mode and equipped with either XONON or SCR. With regard to ammonia slip, the most stringent BACT level established in a preconstruction permit is 10 ppmvd at 15 percent O_2. For facilities equipped with SCONOX, turbines have been required to achieve 2.5 ppm at 15 percent O_2.

With regard to VOC and CO, the most stringent level appearing in a preconstruction permit is 2 ppmvd at 15 percent O_2 for VOC and 6 ppmvd at 15 percent O_2 for CO. This requirement has been applicable to facilities with total generating capacity of more than 5 MW and is consistent with the 1999 ARB Power Plant Guidance for power plants using gas turbines greater than 50 MW and are achievable using oxidation catalyst.

D. Emission Levels Achieved in Practice

Table B-2 lists examples of the most stringent emission levels achieved, based upon emission testing, for NOx, VOC, CO, and ammonia for nine power plants using combustion turbines that are less than 50 MW. The emission data is for natural gas--a couple of facilities were also tested with backup fuels. In general, emission measurement results were available for a broad range of gas turbine sizes - 1.5 MW to 49 MW. For the gas turbines that are rated at less than 10.5 MW, the following emission levels have been achieved: NOx emissions of 2 to 4.6 ppmvd at 15 percent O_2 (XONON and SCONOX for the low end of range and SCR at the

Table B-2
Emission Source Test Results for Combustion Turbine Electrical Generation Less Than 50 MW

Facility Name	District/ State	Description of Basic Equipment	Method of Control	Date Tested	Measured Concentrations (ppmvd @ 15%O2)			
					NOX	VOC	CO	NH3
California Institute of Technology, Pasadena	SCAQMD	Solar Centaur 50-TS900 generating 4.2 MW (58.9 MMBtu/hr) with heat recovery steam generator and steam turbine for total of 5 MW	Water injection / SCR	1/00	4.2	not measured	46	NA
Double C Limited--Oilfield	SJVUAPCD	General Electric LM2500 gas turbine (222 MMBtu/hr) with heat recovery steam generator producing 24 MW	Steam injection / SCR / oxidation catalyst	2/01	2.4	not measured	14.5	not measured
Federal Cold Storage Cogeneration	SCAQMD	General Electric LM2500-M-2 gas turbine (222 MMBtu/hr) and steam turbine producing 32 MW	Water injection/SCONOX	CEM data since 1995	2	not measured	1	NA
Genetics Institute--Andover, Massachusetts	Massachusetts	Solar Taurus 60 generating 5 MW (65 MMBtu/hr) with heat recovery steam generator equipped with duct burner	DLN / SCONOX	2/00 NG 50% load	0.27	NA	0	NA
				2/00 NG 65% load	0.34	NA	0	NA
				2/00 NG 85% load	0.42	NA	0	NA
				2/00 NG 100% load	1.42	NA	0	NA
				2/01 oil 50% load	1.28	NA	0	NA
				2/01 oil 65% load	2	NA	0	NA
				2/01 oil 85% load	2.06	NA	0	NA
				2/01 oil 100% load	5.93	NA	0	NA

Revised: July 23, 2001

Table B-2
Emission Source Test Results for Combustion Turbine Electrical Generation Less Than 50 MW

Facility Name	District / State	Description of Basic Equipment	Method of control	Date Tested	Measured Concentrations (ppmvd @ 15% O2)			
					NOX	VOC	CO	NH3
Genxon Power Systems--Santa Clara	BAAQMD	Kawasaki M1A-13 with Xonon generating 1.5 MW (22.9 MMBtu/hr)	XONON	12/98	2.9	2.7	3.9	NA
High Sierra Limited--Oilfield	SJVUAPCD	General Electric LM2500 gas turbine (222 MMBtu/hr) with heat recovery steam generator producing 25 MW	Steam injection / SCR / oxidation catalyst	3/01	3.6	<0.3	17	<2
Live Oak Limited--Oilfield	SJVUAPCD	General Electric LM5000 gas turbine (460 MMBtu/hr) with heat recovery steam generator producing 49 MW	Steam injection / SCR / oxidation catalyst	4/00	2	<1	1.3	10
Northern California Power--Lodi	SJVUAPCD	General Electric LM5000 gas turbine (460 MMBtu/hr) producing 49 MW	Steam injection / SCR / oxidation catalyst	7/00	2.75	not measured	11.5	24.5
University of California, San Francisco	BAAQMD	(2) Solar Taurus 60 generating 5 MW (76 MMBtu/hr) with heat recovery steam generator equipped with duct burner for total of 10 MW	SCR /oxidation catalyst	5/98 turbine S-9 NG	4	<0.6	0.6	3.2
				5/98 turbine S-11 NG	4.6	<0.6	1.1	3.3
				5/98 turbine S-9 oil	7.8	<1.1	0.6	20.1
				5/98 turbine S-11 oil	7.9	<1.1	1.1	16.1

higher end of the range), trace levels of VOC emissions (XONON less than 3 ppmvd at 15 percent O2), and CO emissions of 1 to 46 ppmvd at 15 percent O_2. For the larger gas turbines, the following emission levels have been achieved: NOx emissions of 2 to 3.6 ppmvd at 15 percent O_2 or better, trace levels of VOC emissions, and CO emissions of 1 to 14.5 ppmvd at 15 percent O_2.

For the gas turbines that are rated at less than 10.5 MW, two generating facilities have achieved the most stringent NOx emission level of 5 ppmvd at 15 percent O_2. These include the UCSF discussed above and the generating facility at California Institute of Technology or CalTech, Pasadena. The unit at CalTech consists of a Solar Centaur 50 (4.6 MW) turbine operated in a combined cycle mode and the turbine is equipped with water injection and SCR. In addition, the University of California, San Francisco facility is also equipped with oxidation catalyst. With the catalyst, the UCSF facility has reduced VOC emissions to the detection level and CO emissions are at 1 ppm—well under the 1999 ARB Power Plant Guidance levels of 2 ppmvd at 15 percent O2 and 10 ppmvd at 15 percent O_2, respectively.

For the larger gas turbines, the lowest level achieved in practice is for the Northern California Power facility in Lodi, which has operated since early-1999. Based upon CEM data and annual inspections, the unit has met the 3 ppmvd NOx limit since startup. The latest compliance test indicated NOx emissions were below 3 ppmvd at 15 percent O_2 and emissions of CO were measured at about 12 ppmvd at 15 percent O_2.

Three other facilities in the San Joaquin Valley have been permitted at NOx level between 3.6 to 4.5 ppmvd at 15 percent O_2, based upon a 3-hour average. These facilities are Live Oak Limited, Double C Limited, and High Sierra Limited. Double C Limited and High Sierra Limited consists of a General Electric LM2500 turbine (25 MW) and heat recovery steam generator. Live Oak Limited consists of a General Electric LM5000 turbine (49 MW) and heat recovery steam generator. All three facilities produce steam for use at an oilfield, and are equipped with SCR and oxidation catalyst. The Live Oak Limited facility has consistently maintained NOx emission levels below 3 ppmvd at 15 percent O_2 since starting up in 2000. Both the Double C Limited and High Sierra Limited facilities were permitted at a higher NOx limit, 4.5 ppmvd at 15 percent O_2, but have typically been between 2.5 to 3.5 ppmvd at 15 percent O_2 based upon three years of annual testing. Finally, the latest compliance test for Live Oak Limited also indicated VOC and CO emissions were near or below the detection level.

XONON's only commercial application is at the Genxon Power Systems facility on a 1.5 MW Kawasaki turbine. The Kawasaki turbine has now operated for 8,000 hours. Compliance tests indicated the NOx emissions are below 3 ppmvd at 15 percent O_2.

SCONOX has been implemented on two turbines, one turbine is 5 MW and the other at 25 MW. The 25 MW turbine at the Federal Cold Storage cogeneration facility has operated for six years, achieving NOx levels of less than 2 ppmvd at 15 percent O_2 when firing natural gas. The 5 MW turbine at the Genetics Institute has operated mainly on fuel oil with some difficulty. However, when the turbine operates for long periods of time using oil, which appears to be the normal operating scenario, the SCONOX technology has experienced masking problems which reduces the effectiveness of the technology in reducing NOx emissions. The masking is reversible, but requires cleaning of the catalyst, and therefore shutdown of the turbine. EmeraChem, (formerly known as Goal Line Environmental Technologies), the developer of the SCONOX technology, has since made modifications to the SCONOX systems at Genetics Institute such that oil usage no longer adversely affects the SCONOX system. After some initial startup problems, the Genetics facility has been reported to have no operating difficulties when operating on natural gas and has satisfied all applicable emission limits. Additional discussion on the applicability of SCONOX is discussed in the next section.

E. More Stringent Control Techniques

1. SCONOX

As can be seen in Tables B-1 and B-2, the SCONOX technology has operating experience at two facilities, the Federal Cold Storage Cogeneration facility on a 25 MW General Electric LM2500 gas turbine in combined cycle mode for total generation of 32 MW and the Genetics Institute facility on a 5 MW gas turbine. The technology has operated for six years at the Federal Cold Storage Cogeneration facility and in that time period, the technology has been improved such that NOx emissions are typically between 1-2 ppmvd at 15 percent O_2. The ARB staff, through its Equipment Precertification Program, has verified the emissions of NOX of 2 ppmvd at 15 percent O_2 over a three-hour rolling average for the Federal Cold Storage Cogeneration facility. For the Genetics Institute facility, as discussed above, after some initial operational problems, which required fine-tuning of the operation of the turbine and the control system, the SCONOX technology has operated well when the turbine uses natural gas. When the turbine uses oil, EmeraChem has apparently resolved its operating issues.

At University of California, San Diego, two 12.5 MW turbines equipped with the SCONOX technology have recently become operational. The July 2001 compliance test indicates NOx emissions levels are below 1 ppmvd at 15 percent O_2 for both turbines. However, prior to the compliance test, the facility was operating under a variance because the facility could not meet its permit limits within the commissioning period (90 days) allocated for shakeout and fine-tuning the facility's operation. Finally, SCONOX is also proposed for the Redding Power facility in Shasta, which would be the largest turbine the technology has been installed to this date.

The SCONOX technology has advantages over SCR in that it can achieve very low NOx emission levels without the emissions of ammonia. In addition, the technology also reduces VOC and CO emissions without the need of adding another control device. However, the technology is substantially more expensive than SCR, there have been few installations, and there has been technical issues associated with the initial operation at each installation. While the ARB staff is not considering the levels achieved by SCONOX for the purposes of establishing guideline levels, district staff should continue to consider SCONOX in BACT determinations for this category.

2. XONON

In the 1999 ARB Power Plant Guidelines report, the XONON technology was identified as a developing technology. Since then, the 1.5 MW Kawasaki gas turbine equipped with the XONON technology has operated over 8,000 hours and during that time period, the turbine has satisfied it NOx emission limit of 5 ppmvd. Catalytica Combustion Systems has applied to the ARB's Equipment and Process Precertification Program to verify that the Kawasaki turbine M1A-13X equipped with XONON demonstrates emissions of 2.5 ppmvd at 15 percent O_2 for a one-hour rolling average and 2.0 ppmvd at 15 percent O_2 for a three-hour rolling average.

While the XONON technology is demonstrated for the Kawasaki gas turbine, it is unclear how well the technology can be applied to larger gas turbines. Catalytica Combustion Systems, the manufacturer of XONON, is in the process of demonstrating the technology on larger gas turbines. A review of Table B-1 indicates that two facilities using 10 MW turbines are proposing to use the XONON technology. Additionally, XONON is also being proposed for use on a large gas turbine (greater than 50 MW).

F. Discussion and Recommendation

As discussed above, for gas turbines used in electrical generation configurations, a review of BACT determinations made by California districts and other states supports establishing emission levels for three class or categories based upon the electrical output of the power plant. These categories are turbines less than 3 MW, 3 MW and up to 12 MW, and greater than 12 MW. The 12 MW cutoff is based upon the greater efficiencies of gas turbines larger than 12 MW—a significant consideration when the emission level is expressed in lb/MW-hr. The lower cutoff is based upon the SCAQMD guidelines establishing a BACT standard for turbines less than 3 MW.

In addition, the recommendations discussed below are largely based upon levels achieved in practice. Consequently, district permitting staffs are encouraged to evaluate the SCONOX or XONON technologies to determine whether either technology is a feasible and cost effective option for a specific application.

1. Gas Turbines Less Than 3 MW

The most stringent BACT levels for gas turbines less than 3 MW is expressed in the SCAQMD and the BAAQMD BACT Guidelines (achieved in practice levels). The guidelines specify BACT at 9 ppmvd at 15 percent O_2 for NOx, 5 ppmvd at 15 percent O_2 for VOC, and 10 ppmvd at 15 percent O_2 for CO. Ammonia slip was also limited to 9 ppmvd at 15 percent O_2. While the Kawasaki turbine (1.5 MW) equipped with the XONON combustors has achieved NOx levels of 2-3 ppmvd at 15 percent O_2, the ARB staff is not recommending this emission level until the XONON technology is available for a wider range of turbines. Based upon the above, the ARB staff recommends BACT levels for gas turbines rated at less than 3 MW to be consistent with these guidelines for such gas turbines.

2. Gas Turbines from 3 MW to 12 MW

Within this size range, both SCR and SCONOX have been used to achieve low NOx levels. The most stringent BACT level achieved in practice was at the Genetics Institute facility in Massachusetts. The Solar Taurus 60 turbine was equipped with SCONOX and when firing natural gas, NOx emissions were less than 2 ppmvd NOx at 15 percent O_2. Despite the reductions achieved by the SCONOX technology, the ARB staff is not recommending a level based upon the SCONOX technology. As discussed above, the SCONOX technology, when compared to SCR, is substantially more expensive and there are technical issues in implementing the technology.

Consequently, the most stringent BACT levels for NOx emissions from gas turbines between 3 MW and 12 MW is 5 ppmvd at 15 percent O_2 averaged over three hours. Several facilities have been permitted at this level and two facilities have achieved this level in practice. The unit at the UCSF and the unit at Cal Tech, Pasadena has achieved this level since 1998. With regard to ammonia slip, the most stringent BACT level established in a preconstruction permit is 10 ppmvd at 15 percent O_2. The unit at the UCSF has achieved this level, as demonstrated by a compliance test.

With regard to VOC and CO, the most stringent level appearing in a preconstruction permit is 2 ppmvd at 15 percent O_2 for VOC and 6 ppmvd at 15 percent O_2 for CO. The unit at the UCSF has achieved this level, as demonstrated by a compliance test.

In light of the above, the ARB staff recommends a BACT level of 5 ppmvd at 15 percent O_2 for NOx, three-hour rolling average, 2 ppmvd at 15 percent O_2 for

VOC, three-hour rolling average, 6 ppmvd at 15 percent O_2 for CO, three-hour rolling average, and 10 ppmvd at 15 percent O_2 for NH3.

3. Gas Turbines Greater Than 12 MW

For gas turbines larger than 12 MW, there are a number of facilities permitted at NOx levels of about 3 ppmvd at 15 percent O_2 or less. The most stringent BACT level required in a preconstruction permit is for the NRG Energy Center Round Mountain facility located in the San Joaquin Valley. The BACT determination was 2 ppmvd at 15 percent O_2 for NOx averaged over three hours. The determination is for a General Electric LM6000 enhanced sprint gas turbine with heat recovery steam generator and equipped with water or steam injection, SCR, and oxidation catalyst. In addition, the CalPeak Power facility has been permitted for NOx levels of 3.4 ppmvd at 15 percent O_2 averaged over three hours and 2.3 ppmvd at 15 percent O_2 on an annual average basis. This determination is for a 24.7 MW Pratt & Whitney FT-8 Twin Pac turbine set equipped with dry low combustors, SCR, and oxidation catalyst. Finally, Northern California Power in Lodi was permitted at 3 ppmvd at 15 percent O_2 averaged over three hours for NOx. The facility consists of a General Electric LM5000 gas turbine.

The lowest level achieved in practice is for Northern California Power facility in Lodi, mentioned above, which has operated since early-1999. Based upon CEM data and annual inspections, the unit has continued to meet the 3 ppmvd NOx since operation. Over this time period, the facility has been cited once by the district for exceeding the ammonia slip limit. The latest compliance test indicated NOx emissions were below 3 ppmvd at 15 percent O_2 and emissions of CO were measured at about 12 ppmvd at 15 percent O_2.

As discussed above, several other facilities in the San Joaquin Valley have been permitted at NOx level between 3.6 to 4.5 ppmvd at 15 percent O_2, based upon a 3-hour average. These facilities are Live Oak Limited, Double C Limited, and High Sierra Limited. The Live Oak Limited facility has consistently maintained NOx emission levels below 3 ppmvd at 15 percent O_2 since starting up in 2000. Both the Double C Limited and High Sierra Limited facilities were permitted at a higher NOx limit, 4.5 ppmvd at 15 percent O_2, but have typically been between 2.5 to 3.5 ppmvd at 15 percent O_2 based upon three years of annual testing. Finally, the latest compliance test for Live Oak Limited also indicated VOC and CO emissions were near or below the detection level.

In addition, the Federal Cold Storage Cogeneration facility has demonstrated levels of less than 2 ppmvd at 15 percent O_2 since 1996, based upon continuous emissions data collected over that period. This facility consists of a General Electric LM2500 gas turbine in a combined cycle generating 32 MW. The gas turbine utilized water injection in conjunction with SCONOX. The ARB staff, through its Equipment Precertification Program, has verified the emissions of NOX of 2 ppmvd at 15 percent O_2 over a three-hour rolling average for the application at the Federal Cold Storage Cogeneration facility.

With regard to VOC, CO, and ammonia, the most stringent level appearing in a preconstruction permit is 2 ppmvd at 15 percent O_2 for VOC, 6 ppmvd at 15 percent O_2 for CO and 5 ppmvd at 15 percent O_2 for ammonia. The VOC and CO levels are consistent with the 1999 ARB Power Plant Guidance for power plants using gas turbines greater than 50 MW and are achievable using oxidation catalyst.

Based on the above, the ARB staff recommends a BACT level of 5 ppmvd at 15 percent O_2 for NOx, three-hour rolling average, 2 ppmvd at 15 percent O_2 for VOC, three-hour rolling average, 6 ppmvd at 15 percent O_2 for CO, three-hour rolling average, and 10 ppmvd at 15 percent O_2 for NH3. However, district permitting staffs are encouraged to evaluate the technical feasible and cost effectiveness of more stringent BACT levels, such as the 3 ppmvd at 15 percent O_2 limit for NOx, or the use of advance control technologies including the SCONOX or XONON technologies as part of the case-by-case BACT determination for power generating projects.

III. NON-EMERGENCY RECIPROCATING ENGINES USING FOSSIL FUELS

As discussed below, some districts are beginning to develop BACT requirements that are fuel neutral. For example, the SCAQMD BACT Guidelines for minor sources specifies BACT for NOx emissions from reciprocating engines used in nonemergency applications as 0.15 g/bhp-hr. Based upon this approach, the BACT levels can only be satisfied by a well controlled natural gas fueled reciprocating engine. At this time, diesel fueled engines cannot achieve this emission level. Consequently, the discussion below focuses on the emission levels achieved by natural gas fueled reciprocating engines.

A. Control Technologies

The combustion of natural gas in reciprocating engines results in emissions of the following criteria pollutants: NOx, CO, VOC, PM, and sulfur oxides (SOx). For natural gas, the emissions of PM and SOx result from the amount of sulfur in the fuel. The sulfur concentration in "pipeline quality" natural gas is regulated by the Public Utilities Commission. Consequently, no recommendations will be provided for PM and SOx emissions. However, staff will recommend that a PM standard be added in the event diesel-fueled engines are able to achieve the same emission levels as natural gas fueled reciprocating engines. This PM level is consistent with the technology requirements of the ARB diesel risk management guidance.

For the remaining pollutants, the pollutant of primary concern from stationary reciprocating engines is NOx, a criteria pollutant that reacts in the atmosphere to form ozone which is a significant air pollution problem in California. To reduce NOx emissions from natural gas fueled reciprocating engines, BACT levels are typically achieved with post-combustion controls, including nonselective catalytic reduction (NSCR) or three-way catalyst for rich-burn engines or SCR for lean-burn engines. The major difference between rich-burn and lean-burn engines is in the amount of excess air used for combustion. Rich-burn engines use nearly equal mixture of air and fuel while lean-burn engines use significantly more air than fuel.

Similarly, BACT levels for CO and VOC emissions are also based upon post-combustion controls. Three-way catalyst is used to reduce CO and VOC emissions from rich-burn engines and oxidation catalyst is used to reduce CO and VOC emissions from lean-burn engines.

A detailed description of both the SCR or CO/VOC oxidation catalyst technologies are given in the 1999 ARB Power Plant Guidance Report. A description of the NSCR technology is given below.

1. Nonselective Catalytic Reduction

The NSCR technology or three-way catalyst, which is the same technology used to reduce emissions from motor vehicle gasoline engines and has been used on rich-burn stationary engines for over 15 years, employs a catalyst that reduces the emissions of NOx, CO, and VOC. Three-way catalyst promotes the chemical reduction of NOx in the presence of CO and VOC to produce oxygen and nitrogen. The three-way catalyst also contains materials that promote the oxidation of VOC and CO to form carbon dioxide and water vapor. The standard catalyst typically achieves 90 percent reduction in NOx, 50 percent reduction in VOC, and 80 percent reduction in CO. A premium catalyst is able to achieve higher reductions in NOx--up to 99 percent. An electronic controller, which includes an oxygen sensor and feedback mechanism, is necessary to maintain the proper air/fuel ratio. The three-way catalyst system operates in a narrow air/fuel ratio band--operation outside the band can dramatically increase either NOx or CO emissions. In addition, the three-way catalyst technology achieves its optimal reduction within a certain temperature band.

B. Current SIP Control Measures

Several districts have adopted SIP control measures specifying reductions in NOx emissions from reciprocating engines. The most stringent of these measures has been adopted by SCAQMD, AVAPCD, and Ventura County Air Pollution Control District (VCAPCD). Both measures set emission standards for NOx, VOC, and CO.

The SCAQMD and AVAPCD requires reciprocating engines to meet the following emission standards: 36 ppmvd at 15 percent O_2 for NOx, 250 ppmvd at 15 percent O_2 for VOC, and 2,000 ppmvd at 15 percent O_2 for CO. Alternate levels, which are higher than the general requirement, for NOx and VOC are allowed, based upon the efficiency of the engine.

VCAPCD requirements for reciprocating engines vary based upon the type of engine and the standard can be satisfied by meeting an emission standard or achieving a specified percentage of emission reduction. The NOx emission standard varies from 25 to 80 ppmvd at 15 percent O_2. Similarly, the VOC standard varies from 250 to 750 ppmvd at 15 percent O_2 and the CO standard is 4,500 ppmvd at 15 percent O_2 for all type of engines. The emission reduction component applies to NOx only and reductions of 90 to 96 percent must be achieved, with the specific level based upon the engine type, to avoid the emission specific standard.

C. Control Techniques Required as BACT

1. BACT Guidelines

Of the districts with published BACT guidelines, the most stringent requirements are those requirements in the SCAQMD guidelines. For all stationary reciprocating engines used in a non-emergency application that are less than 2,064 bhp, the levels are set at 0.15 g/bhp-hr for NOx, 0.15 g/bhp-hr for VOC, and 0.6 g/bhp-hr for CO. For larger engines, the BACT guidelines specify standards for NOx (which allows higher emissions for engines with efficiencies greater than 33 percent) and CO (50 percent more stringent than the level specified for smaller engines) only. The only deviation from this BACT level is for landfill or digester gas fired engines, which will be discussed in the next section.

2. BACT Determinations

Table B-3 lists 17 examples of the most stringent emission controls required as BACT, by California districts or other states, for emissions of NOx, VOC, CO, and if applicable, ammonia from reciprocating engines. The engines range in size from about 80 horsepower (hp) to over 4,000 hp.

The determinations listed in Table B-3 can be separated into determinations for rich-burn engines and determinations for lean-burn engines. For rich-burn engines, the use of three-way catalyst and air/fuel ratio controller has been used to achieve BACT levels of 0.15 g/bhp-hr (which is equivalent to about 9 ppmvd at 15 percent O_2) for NOx. The SCAQMD has specified 0.15 g/bhp-hr as BACT for NOx emissions from natural gas-fueled reciprocating engines used in nonemergency applications since 1998 and the next section provides a number of examples demonstrating that this level is achieved in practice. With regard to BACT levels for

Table B-3
Emission Control Requirements for Engines Using Fossil Fuel

Facility Name	District / State	Description of Basic Equipment	Method of control	Permit Status	BACT Level (g/bhp-hr)*			
					NOX	VOC	CO	NH3
Aera Energy--Oilfield	SJVUAPCD	(5) 800 bhp Superior 8G-825 rich-burn engines or (3) 1478 bhp Waukesha 7042 GSI rich-burn engines driving natural gas compressors	3-way catalyst: Quick-Lid 3-DC74 and air/fuel ratio controller	ATC 1/01	0.071	0.069	0.603	NA
Claremont Club--Claremont	SCAQMD	(3) 86 bhp rich-burn engine cogeneration system	3-way catalyst: Miratech MN-11T-04F and air/fuel ratio controller	PTO 5/01	0.15	0.15	0.6	NA
College of the Desert--Palm Desert	SCAQMD	161 bhp Tecochill/Tecogen 74000LE rich-burn engine driving a compressor	3-way catalyst and air/fuel ratio controller	PTO 8/99	0.15	0.15	0.6	NA
Crestline Village Water District--Crestline	SCAQMD	94 bhp Ford LSG875 rich-burn engine driving a generator	3-way catalyst: Miratech MN-09-04F-D2 and air/fuel ratio controller	PTO 10/00	0.15	0.15	0.6	NA
Gill's Onions--Oxnard	Ventura Co. APCD	(3) 158 bhp Tecodrive 7400LE rich-burn engine driving refrigeration compressor; 250 bhp Waukesha F11 GSID rich-burn engine driving an air compressor; and 815 bhp Caterpillar G3512 rich-burn engine driving an air compressor	3-way catalyst and air/fuel ratio controller	ATC 4/98	9 ppmvd	27 ppmvd	62 ppmvd	NA
JST Energy LLC--Red Bluff	Tehama Co. APCD	(10) 3,928 bhp Wartsila 18V220SG lean-burn engine driving 2,926 KW generator for a total of 29 MW	SCR and oxidation catalyst: Miratech/Hug EM77/6 SCR and Oxicat oxidation catalyst	ATC 5/01	0.07 or 8 ppmvd	0.15 or 50 ppmvd	0.56 or 107 ppmvd	10 ppmvd

Table B-3
Emission Control Requirements for Engines Using Fossil Fuel

Facility Name	District / State	Description of Basic Equipment	Method of control	Permit Status	BACT Level (g/bhp-hr)*			
					NOX	VOC	CO	NH3
Kaiser Permanente--Los Angeles	SCAQMD	(4) 171 bhp Tecodrive model 7400LE rich-burn engines use to drive two compressors / chillers that will provide cooling for the facility	3-way catalyst: Miratech MN-11T-04F and tecodrive air/fuel ratio controller	PTC 12/99	0.15	0.15	0.6	NA
Los Angeles County, Metropolitan Transit Authority--Los Angeles	SCAQMD	400 bhp Caterpillar G3408TA HCR rich-burn engine driving a compressor	3-way catalyst: Johnson Mathey QXH50-8 and air/fuel ratio controller	PTO 9/99	0.15	0.15	0.6	NA
NEO California Power LLC--Chowchilla	SJVUAPCD	(16) 4,157 bhp Deutz TBG632V16 lean-burn engine driving 3,100 KW generator for total of 49.6 MW	SCR and oxidation catalyst	ATC 3/01	0.07	0.15	0.1	10 ppmvd
NEO California Power LLC--Red Bluff	Tehama Co. APCD	(16) 3,928 bhp Wartsila 18V220SG lean-burn engine driving 2,926 KW generator for a total of 46.7 MW	SCR and oxidation catalyst: Miratech/Hug EM77/6 SCR and Oxicat oxidation catalyst	ATC 4/01	0.07	0.15	0.56	10 ppmvd
Saba Petroleum	Santa Barbara Co. APCD	747 bhp Waukesha 3521GSI rich-burn engine driving a compressor	3-way catalyst and air/fuel ratio controller	ATC 10/98	0.15	0.3	0.75	NA
SB Linden--Linden, NJ	NJDEP	3,130 bhp Waukesha 12VAT27GL lean-burn engine driving a pump	SCR and oxidation catalyst	ATC 12/96	50 ppmvd	58 ppmvd	76 ppmvd.	10 ppmvd
Tosco-Ventura Pump Station--Ventura	Ventura Co. APCD	415 bhp Caterpillar SP321P001G379ASI rich-burn engine driving a pump	3-way catalyst: Quick-Lid and air/fuel ratio controller	ATC 12/97	9 ppmvd	100 ppmvd	1,000 ppmvd	NA

Table B-3
Emission Control Requirements for Engines Using Fossil Fuel

Facility Name	District / State	Description of Basic Equipment	Method of control	Permit Status	BACT Level (g/bhp-hr)*			
					NOX	VOC	CO	NH3
Trillium USA--Los Angeles	SCAQMD	(3) 607 bhp Caterpillar G3412TAA rich-burn engine driving a compressor	3-way catalyst: Miratech EQ-700-XX-D2 and tecodrive air/fuel ratio controller	PTO 7/99	0.15	0.15	0.6	NA
Trillium USA--West Hollywood	SCAQMD	(3) 607 bhp Caterpillar G3412TAA rich-burn engine driving a compressor	3-way catalyst: Miratech EQ-700-XX-D2 and tecodrive air/fuel ratio controller	PTO 7/99	0.15	0.15	0.6	NA
Veterans Administration Medical Center--Brockton	Massachusetts	2,113 bhp Waukesha 8LAT27GL lean-burn engine driving a 1.5 MW generator	SCR and oxidation catalyst	ATC 4/01	0.15	0.6	0.16	5 ppmvd
Vintage Petroleum--Piru	Ventura Co. APCD	325 bhp Caterpillar 3406TA rich-burn engine driving a pump	3-way catalyst and air/fuel ratio controller	ATC 98	9 ppmvd	110 ppmvd	1,000 ppmvd	NA

* unless indicated otherwise (for example, ppmvd means parts per million by volume, dry at 15 pecent O2)

VOC and CO, recent determinations have limited VOC levels to 0.15 g/bhp-hr (about 25 ppmvd at 15 percent O_2) and CO levels to 0.6 g/bhp-hr (about 56 ppmvd at 15 percent O_2). Examples of engines permitted at these levels range in size from about 80 hp to about 1,500 hp.

San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) has recently made a more stringent BACT determination for NOx of 0.071 g/bhp-hr (5 ppmvd at 15 percent O_2), VOC at 0.069 g/bhp-hr (14 ppm at 15 percent O_2) and CO at 0.6 g/bhp-hr (70 ppm at 15 percent O_2)--see entry for Aera Energy in Table B-3. This determination is based upon a vendor guarantee for the emission level for either a 800 bhp Superior 8G-825 natural gas-fired engine or a 1,478 bhp Waukesha 7042 GSI engine, depending upon which engine is ultimately purchased. These engines would be driving natural gas compressors.

For lean-burn engines, recent BACT determinations have been based upon the use of SCR to achieve BACT level for NOx and oxidation catalyst to achieve BACT level for VOC and CO. As equipped, the BACT level for NOx has been set at 0.071 g/bhp-hr (5 ppm at 15 percent O_2), VOC levels at 0.15 g/bhp-hr (30 ppm at 15 percent O_2) and CO levels at 0.1 g/bhp-hr (12 ppm at 15 percent O_2). Ammonia slip is limited to 10 ppmvd at 15 percent O_2. This determination is for a 4,157 hp Deutz TBG632V16 lean burn engine equipped with SCR and oxidation catalyst.

D. Emission Levels Achieved in Practice

Table B-4 lists 23 examples from 14 different facilities of the most stringent emission levels achieved, based upon emission testing, for NOx, VOC, CO, and if applicable, ammonia for reciprocating engines at several facilities. Engines tested range in size from 86 hp engine up to 713 hp for rich-burn engines and over 3,000 hp for lean-burn engines. In most cases, the testing was done to satisfy annual compliance demonstration requirements. Consequently, some of the reciprocating engines have been tested for up to four years.

For the rich-burn engines, the test results shown in Table B-4 indicate that the 0.15 g/bhp-hr or 9 ppmvd at 15 percent O_2 NOx BACT level has been satisfied, in one instance, for over four years. Two 713 hp Caterpillar G398TAHC engines have operated since 1997 at Los Alamos Energy. Engine #2 has been in compliance with the NOx standard for four consecutive years, and the emissions of NOx have been below 5 ppmvd at 15 percent O_2 for the first three years. Conversely, engine #1 failed the 1998 compliance test. After a replacement of the catalyst, the engine passed the retest and has since satisfied subsequent compliance tests. In general, catalyst, with proper maintenance, is expected to have a two-year lifetime under continuous operation.

Additionally, the NOx concentrations with a new catalyst are typically well below the 9 ppmvd BACT level--in some cases, initial tests have shown results

Table B-4
Emission Source Test Results for Engines Using Fossil Fuel

Facility Name	District / State	Description of Basic Equipment	Method of control	Date tested	Engine or test #	Measured Concentrations (ppmvd @ 15% O2)* NOX	VOC	CO
Claremont Club--Claremont	SCAQMD	(3) 86 bhp rich-burn engine cogeneration system	3-way catalyst: Miratech MN-11T-04F and air/fuel ratio controller	10/00	engine #1	0.112 gm/bhp-hr	0.035 gm/bhp-hr	0.091gm/bhp-hr
					engine #2	0.003 gm/bhp-hr	0.044 gm/bhp-hr	0.142 gm/bhp-hr
					engine #3	0.005 gm/bhp-hr	0.026 gm/bhp-hr	0.075 gm/bhp-hr
College of the Desert--Palm Desert	SCAQMD	161 bhp Tecochill/Tecogen 74000LE rich-burn engine driving a compressor	3-way catalyst and air/fuel ratio controller	1/99	NA	0.044 gm/bhp-hr or 7 ppmvd	0.085 gm/bhp-hr or 38 ppmvd	0.255 gm/bhp-hr or 64 ppmvd
Crestline Village Water District--Crestline	SCAQMD	94 bhp Ford LSG875 rich-burn engine driving a generator	3-way catalyst: Miratech MN-09-04F-D2 and air/fuel ratio controller	7/00	NA	<0.15 gm/bhp-hr or <20 ppmvd	0.02 gm/bhp-hr or 3 ppmvd	0.34 gm/bhp-hr or 31 ppmvd
Gill's Onions--Oxnard	Ventura Co. APCD	158 bhp Tecodrive 7400LE rich-burn engine driving refrigeration compressor and 250 bhp Waukesha F11 GSID driving air compressor	3-way catalyst and air/fuel ratio controller	1/00	Tecodrive #1	7	5.8	55
					Waukesha	5	1.4	10
Gill's Onions--Oxnard	Ventura Co. APCD	(2) 158 bhp Tecodrive 7400LE rich-burn engine driving a refrigeration compressor and 815 bhp Caterpillar G3512 rich-burn engine driving an air compressor	3-way catalyst and air/fuel ratio controller	11/00	Tecodrive #2	2	<0.5	30
					Tecodrive #3	8	<0.5	58
					Caterpillar	4.5	2.1	50

Table B-4
Emission Source Test Results for Engines Using Fossil Fuel

Facility Name	District / State	Description of Basic Equipment	Method of control	Date tested	Engine or test #	Measured Concentrations (ppmvd @ 15%O2)* NOX	VOC	CO
Gill's Onions--Oxnard	Ventura Co. APCD	158 bhp Tecodrive 7400LE rich-burn engine driving refrigeration a compressor and 250 bhp Waukesha F11 GSID rich-burn engine driving an air compressor	3-way catalyst and air/fuel ratio controller	2/01	Tecodrive #1	0.8	<0.5	12
					Waukesha	6.3	<0.5	6
Los Alamos Energy	Santa Barbara Co. APCD	(2) 713 bhp field gas-fired Caterpillar G398TAHC rich-burn engine driving a generator producing a total of 0.93 MW	3-way catalyst and air/fuel ratio controller	1997	engine #1	3.6	0.14	165
				1998	engine #1	65**	NA***	NA
				1999	engine #1	13	NA	NA
				1999	engine #1	11	NA	NA
				2000	engine #1	3	NA	NA
				1997	engine #2	0.6	0.16	87
				1998	engine #2	4	0.8	714
				1999	engine #2	5	NA	NA
				2000	engine #2	11	NA	NA

Table B-4
Emission Source Test Results for Engines Using Fossil Fuel

Facility Name	District / State	Description of Basic Equipment	Method of control	Date tested	Engine or test #	Measured Concentrations (ppmvd @ 15%O2)*		
						NOX	VOC	CO
Los Angeles County, Metropolitan Transit Authority--Los Angeles	SCAQMD	400 bhp Caterpillar G3408TA HCR rich-burn engine driving a compressor	3-way catalyst: Johnson Mathey QXH50-8 and air/fuel ratio controller	9/99	NA	0.01gm/bhp-hr or <2 ppmvd	0.03 gm/bhp-hr or 7 ppmvd	0.12 gm/bhp-hr or 15 ppmvd
Saba Petroleum	Santa Barbara Co. APCD	747 bhp Waukesha 3521GSI rich-burn engine driving a compressor	3-way catalyst and air/fuel ratio controller	1999	NA	0.14 gm/bhp-hr	0.04 gm/bhp-hr	0.36 gm/bhp-hr
				2000	NA	0.065 gm/bhp-hr	0.01 gm/bhp-hr	0.13 gm/bhp-hr
SB Linden--Linden, NJ	NJDEP	3,130 bhp Waukesha 12VAT27GL lean-burn engine driving a pump	SCR and oxidation catalyst	1997	test #1	16.5	NA	26.5
					test #2	13.9	NA	25.8
					test #3	14	NA	25.1
					test #4	15.6	NA	24.8
Trillium USA--Los Angeles	SCAQMD	(3) 607 bhp Caterpillar G3412TAA rich-burn engine driving a compressor	3-way catalyst: Miratech EQ-700-XX-D2 and tecodrive air/fuel ratio controller	11/00	Unit A	0.024 gm/bhp-hr	0.008 gm/bhp-hr	0.016 gm/bhp-hr
					Unit B	0.009 gm/bhp-hr	0.004 gm/bhp-hr	0.15 gm/bhp-hr
					Unit C	0.06 gm/bhp-hr	0.004 gm/bhp-hr	0.31 gm/bhp-hr

Table B-4
Emission Source Test Results for Engines Using Fossil Fuel

Facility Name	District / State	Description of Basic Equipment	Method of control	Date tested	Engine or test #	Measured Concentrations (ppmvd @ 15%O2)*		
						NOX	VOC	CO
Trillium USA--West Hollywood	SCAQMD	(3) 607 bhp Caterpillar G3412TAA rich-burn engine driving a compressor	3-way catalyst: Miratech EQ-700-XX-D2 and tecodrive air/fuel ratio controller	8/00	Unit A	0.1 gm/bhp-hr	0.007 gm/bhp-hr	0.34 gm/bhp-hr
					Unit B	0.1 gm/bhp-hr	0.01 gm/bhp-hr	0.4 gm/bhp-hr
Tosco-Ventura Pump Station--Ventura	Ventura Co. APCD	415 bhp Caterpillar SP321P001-G379ASI rich-burn engine driving a pump	3-way catalyst and air/fuel ratio controller	ARB test 3/01	NA	1.2	58.4****	245
				1/01	NA	3.4	6	180
Vintage Petroleum--Piru	Ventura Co. APCD	325 bhp Caterpillar 3406TD rich-burn engine driving a pump	3-way catalyst and air/fuel ratio controller	9/99	NA	7	76	381

* unless otherwise indicated

** original test did not meet district standard. After modifications, engine was retested.

*** test for CO and VOC taken in lb/day--no data available in ppm

**** total hydrocarbons

below 2 ppmvd at 15 percent O_2. Fourteen of the 21 initial compliance test were below 5 ppmvd at 15 percent O_2 for NOx and of the 32 total tests shown in Table B-4, 20 of the test results were below 5 ppmvd at 15 percent O_2.

The experience gained in using a three-way catalyst in thousands of applications has identified the pitfalls to be avoided in order to ensure the optimum effectiveness and life of the control system. For example, initial catalyst masking problems were solved by using an ash-free lube oil. Catalytic converter manufacturers now require limits on certain chemical poisons in both the lube oil and the fuel used in the engine. Temperature of the fuel gas also plays a role in that optimum efficiency occurs within a certain temperature window and that the excessive heat for the catalytic converter can also adversely affect the life and overall emission reduction of the unit. Additionally, certain applications involving significant idle conditions could result in reduced overall efficiency of the catalyst due to not maintaining the proper temperature requirements. Modifying the operation of the engine by reducing the idling time solved this issue.

For lean-burn engines, there is only one emission test result available. The results of the compliance test for the SB Linden, New Jersey engine indicates the measured NOx levels are well below the NOx permit limit of 50 ppmvd at 15 percent O_2, averaging about 15 ppmvd at 15 percent O_2—about 70 percent lower than the original permit limit. The NEO California Power LLC power plant located in Chowchilla, composed of 16 large lean-burn engines equipped with SCR and oxidation catalyst initiated operation in early June 2001. Similarly, the NEO California Power LLC Red Bluff facility initiated operation in August 2001. Source test results for both facilities should be available later in 2001.

E. More Stringent Control Techniques

1. Technologically Feasible Controls

a. NoxTech

The technology is relatively new and has only been applied commercially to diesel engine generators with great success--achieving over 90 percent reduction in NOx emissions over a two year period. A description of the technology is given in Appendix B of the draft ARB report: Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines, April 2000. This report is scheduled to be finalized later this year.

This control method should be effective on lean-burn engines, subject to the limits discussed below. The major concern is the cost effectiveness of NOxTech. Because of the high energy needs for the technology (the fuel penalty can be as high as 10 percent), the operating cost associated with using NoxTech is higher than with SCR. Consequently, this technology may not be cost effective for engines that do not operate at a high operating capacity. Additionally, NoxTech may not be suitable for engines that do not operate with a relatively constant load.

2. Developing Control Technologies

a. SCONOX

As discussed above, the focus of the SCONOX technology has only been used for reducing NOx emissions from gas turbines. EmeraChem is now adapting the SCONOX technology to reduce NOx emissions from engines. For example, SCONOX was installed on two large natural gas-fueled engine generators at Texas Instruments. However, the facility subsequently closed prior to the commercial operation of the two engines. In addition, EmeraChem is working with Cummins to adapt the SCONOX technology to diesel engines.

In summary, it appears that SCONOX technology could be applied to lean-burn or rich-burn engines. However, the technology has not been used to control the emissions from an engine outside of a laboratory setting. In the application of the technology on gas turbines, there have been technical issues at each of its installations regarding the initial implementation of the technology. Consequently, commercial demonstrations are needed to dispel these concerns. In addition, it is unclear what the overall cost effectiveness of the SCONOX technology is relative to other control techniques used for engines.

b. Lean NOx Catalyst

This technology is being developed to reduce emissions from diesel engines used in on-highway applications. This control method is still in the developmental stage and is not expected to be commercially available until the end of the decade. The efficiency for the technology, based upon laboratory tests, for reducing NOx emissions ranges from 25-50 percent, which is considerably less than the levels achieved by either SCR or SCONOx. The Manufacturers of Emission Controls Association (MECA) report Emission Control Technology for Stationary Internal Combustion Engines, 1997 indicated that in a test on a stationary engine, reductions of 80 percent were achieved.

F. Discussion and Recommendation

The most stringent BACT level for a reciprocating engine was required in the preconstruction permits for NEO California Power LLC (for two locations: Chowchilla and Red Bluff), JST Energy LLC located at Red Bluff, and Aera Energy for engines located in the oil fields of San Joaquin Valley. The determination for

NEO California Power and JST Energy was made for lean-burn engines (4,157 bhp Deutz model TBG632V16 and 3,928 bhp Wartsila model 18V220SG) equipped with SCR and oxidation catalyst. BACT levels were specified at 0.07 g/bhp-hr for NOx, 0.15 g/bhp-hr for VOC, and 0.6 g/bhp-hr for CO. The other determination for Area Energy was for a rich-burn engine (either an 800 bhp Superior 8G-825 engine or a 1,478 bhp Waukesha 7042 GSI engine) equipped with a three-way catalyst. BACT levels were specified at 0.071 g/bhp-hr for NOx, 0.069 g/bhp-hr for VOC, and 0.6 g/bhp-hr for CO.

The lowest emissions achieved in practice for a lean-burn engine are for the 2,113 bhp Waukesha model 8LAT27GL engine located at the SB Linden facility located in New Jersey. The BACT determination limited emissions of the engine to 50 ppmvd at 15 percent O_2 for NOx, 58 ppmvd at 15 percent O_2 for VOC, and 76 ppmvd at 15 percent O_2 for CO. The engine has been in operation since 1997 and emission tests conducted in 1997 indicated NOx emissions were well below the limit in the preconstruction permit. The measurements were 17 ppmvd at 15 percent O_2 or less, and CO emissions was also well below the limit in the preconstruction permit, measuring in all cases below 27 ppmvd at 15 percent O_2. The equivalent g/bhp-hr is 0.2 for both NOx and CO. VOC emission was measured with a test method not consistent with methods used in California and therefore, is not included in this analysis.

The most stringent BACT levels achieved in practice for a rich-burn engine are the emission levels currently specified as BACT in the SCAQMD--these levels are applicable to all nonemergency reciprocating engines. These emission levels are 0.15 g/bhp-hr (9 ppmvd at 15 percent O_2) for NOx, 0.15 g/bhp-hr (25 ppmvd at 15 percent O_2) for VOC, and 0.6 g/bhp-hr (56 ppmvd at 15 percent O_2) for CO. These emission standards have represented BACT since 1998. In addition, engines varying in size from 86 bhp to 747 bhp engines have been equipped with three-way catalyst to satisfy these emission standards.

For rich-burn engines, as discussed above, in satisfying a BACT level of 9 ppmvd at 15 percent O_2 or 0.15 g/bhp-hr, 60 percent of all engines with test data achieved a 5 ppmvd at 15 percent O_2 or 0.07 g/bhp-hr emission level for NOx or better. Additionally, 65 percent of the engines achieved this level for NOx in the initial compliance test. This level has been achieved for a wide range of engine horsepower sizes: from about 80 hp up to about 750 hp. In addition, one engine at Los Alamos Energy has operated with three-way catalyst since 1997 and over this period, has been below 5 ppmvd at 15 percent O_2 for three years.

The control technologies identified to attain the most stringent level contained in a preconstruction permit are the same control technologies used to reach the lowest level achieved in practice. The ARB staff believes the BACT levels of 0.07 g/bhp-hr for NOx, 0.15 g/bhp-hr for VOC, and 0.6 g/bhp-hr for CO are technically achievable. To attain these levels, additional amounts of catalysts will be required, and in the case of SCR, additional amounts of ammonia/urea may need to be used.

Based upon the above, the ARB staff recommends establishing a BACT level based upon the achieved in practice levels of the SCAQMD requirements for nonemergency engines. As discussed above, the staff believes the 0.07 g/bhp-hr level proposed in the permits for Aera Energy and for NEO California Power is technically achievable. Consequently, district permitting staffs are encouraged to evaluate these BACT levels represented by these projects as part of the technical feasibility portion of the case-by-case BACT determination for power generating projects. In addition, once the NEO California Power has demonstrated achievement of the 0.07 g/bhp-hr NOx level, the ARB staff will consider this level to be achieved in practice for its class and category. Finally, an emission limit for PM was added. This PM level is consistent with the technology requirements of the ARB report entitled Risk Management Guidance for the Permitting of New Stationary Diesel-Fueled Engines, October 2000.

IV. INTERAL COMBUSTION ENGINES OR GAS TURBINES USING WASTE GASES

Both reciprocating engines and gas turbines have been used to recover energy at landfills and wastewater treatment facilities. At landfills, to ensure the removal of toxic emissions, landfill gas is usually flared. From an energy perspective, no energy benefit is realized if the gas is flared. Consequently, the combustion of landfill gas in either engines or gas turbines to recovery energy from landfill gas that would otherwise be flared is beneficial from both an energy perspective and in reduction of green house gases. Digesters at wastewater treatment facilities are an ideal combined heat and power application in that the engine can produce both heat and electricity--the heat is needed in the digestion process and the electricity can be used to power equipment at the facility.

A. Control Technologies

Both landfill and digester gas contains impurities that, if combusted will likely poison post-combustion control systems that are based upon catalysts. Consequently, the approach for combusting waste gas in either a reciprocating engine or gas turbine has centered on either combustion processes that result in minimal NOx being produced such as low NOx burners for gas turbines and noncatalytic control systems such as steam/water injection for a gas turbine. For reciprocating engines, lean-burn engines have been the choice because these types of engines produce the lowest emission of NOx without using post combustion treatment technologies. In the case of gas turbines, the control techniques used in these applications include either low NOx combustors or water/steam injection to reduce NOx emissions.

B. Current SIP Control Measures

While there are no specific SIP control measures specifying reductions from waste gas combustion, many SIP measures affecting reciprocating engines have provisions affecting engines used in waste gas applications or have emission limits for lean-burn engines. The most stringent SIP measures have been adopted by SCAQMD, AVAPCD, and SDCAPCD. Both measures set emission standards for NOx, VOC, and CO. The SCAQMD and AVAPCD require reciprocating engines using waste gas to meet the following emission standards: 50-63 ppm at 15 percent O_2 for NOx, 350-440 ppm at 15 percent O_2 for VOC, and 2000 ppm at 15 percent O_2 for CO, with the applicable NOx and VOC standard depending upon the efficiency of the engine. SDCAPCD does not regulate waste gas usage, but requires lean-burn engines to achieve either 65 ppm at 15 percent O_2 or 90 percent reduction for NOx.

For gas turbines, the most stringent of these measures has been adopted by SCAQMD and AVAPCD. For the turbines typically used in landfill applications, these measures limit the NOx emissions from 9 to 25 ppmvd at 15 percent O2, based upon the size and efficiency of the turbine. In addition, a limit of 25 ppmvd applies to turbines between 2.9 and 10 MW which use a fuel with a minimum percentage of 60 percent sewage digester gas.

C. Control Techniques Required as BACT

1. BACT Guidelines

Of the districts with published BACT guidelines, the most stringent requirements for reciprocating engines or gas turbines fueled with either landfill or digester gas have been proposed by SCAQMD. For all stationary reciprocating engines using either landfill gas or digester gas, the levels are set at 0.6 g/bhp-hr for NOx, 0.6 g/bhp-hr for VOC, and 2.5 g/hp-hr for CO. Similarly, for gas turbines using either landfill gas or digester gas, the levels are set at 25 ppmvd at 15 percent O_2 for NOx and 130 ppmvd at 15 percent O_2 for CO.

2. BACT Determinations

Tables B-5 and B-6 list the most stringent emission controls required as BACT, by California districts, for emissions of NOx, VOC, CO, for engines used in landfill gas applications and engines or turbines used in digester gas applications respectively. For engines used in landfill applications, examples of district BACT determinations are for engines ranging from about 850 hp up to over 4,000 hp.

Table B-5
Emission Control Requirements for Engines And Gas Turbines Using Landfill Gas

Facility Name	District / State	Description of Basic Equipment	Method of control	BACT Level (g/bhp-hr)*			
				Permit Status	NOX	VOC	CO
County of Sacramento--Kiefer Landfill	Sacramento Metropolitan AQMD	(3) 4,230 bhp Caterpillar G3616 lean-burn engine driving a 3 MW electric generator	Lean-burn technology	ATC 8/98	0.55	NA	2.7
Energy Developments Inc--Azusa Landfill	SCAQMD	(5) 1,850 bhp Deutz TBG620 v16k lean-burn engine driving a generator	Lean-burn technology	PTC 5/00	0.6	0.17	2
Minnesota Methane Tajiguas Corporation-- Tajiguas Landfill	Santa Barbara Co. APCD	4,314 bhp Caterpillar 3616 lean-burn engine driving a 3 MW electric generator	Lean-burn technology	ATC 1/98	0.59	0.24	2.5
Riverside County Waste Management--Badlands	SCAQMD	1,777 bhp Deutz TBG620 v16k lean-burn engine driving a generator	Lean-burn technology	PTC 11/98	0.31	0.02	1.49
University of California at Los Angeles--Los Angeles	SCAQMD	(2) General Electric LM1600 generating 14.4 MW (140 MMBtu/hr) with heat recovery steam generator and steam turbine for total of 48 MW	Water injection and SCR	PTO 1995	6 ppmvd	NA	10 ppmvd

* unless otherwise indicated; ppmvd expressed at 15% O2.

Table B-6
Emission Control Requirements for Engines or Turbines Using Digester Gas

Facility Name	District / State	Description of Basic Equipment	Method of control	Permit Status	BACT Level (g/bhp-hr)*		
					NOX	VOC	CO
City of Stockton	SJVUAPCD	(3) 1,408 bhp Waukesha L7042GLD digester/natural gas lean-burn engine generating 1.05 MW each for a total of 3.15 MW; cogeneration: electricity used onsite and hot water generated for digester	Lean-burn technology	ATC 10/99	1.25	0.75	2.65
Hemet/San Jacinto Regional Water Reclamation Facility--San Jacinto	SCAQMD	260 bhp Caterpillar G379 SI-TA-HCR spark ignition digester gas-fired, with pre stratified charge system driving a aeration blower	Pre-stratified charge system	ATC 2/99	0.6	0.8	2.5
Joint Water Pollution Control Plant--Carson	SCAQMD	(3) Solar Mars 90 generating 9.9 MW (113 MMBtu/hr) with heat recovery steam generator and one 5.1 MW steam turbine for total of 34.8 MW	Water injection	ATC 7/00	25 ppmvd	NA	NA

* unless otherwise indicated; ppmvd expressed at 15% O2.

Similarly, examples of BACT determinations for digester gas fired engines include two reciprocating engines (260 hp and 1,400 hp) and a gas turbine.

For engines combusting either landfill or digester gas, the recent NOx BACT determinations have required lean-burn engines to achieve 0.55-0.6 g/bhp-hr (40-45 ppmvd at 15 percent O_2). There was one district determination specifying BACT for NOx emissions as 0.31 g/bhp-hr (See Riverside County Waste Management--Badlands), based upon an applicant's proposal, which is considerably lower than the other BACT determinations listed in Table B-5. This level is based upon a vendor guarantee.

There has been a wider range of emission levels established for BACT for the other pollutants. VOC BACT emission levels have been specified at 0.75 -0.8 (160-170 ppmvd at 15 percent O_2) when using digester gas and 0.25 g/bhp-hr or less (50 ppmvd at 15 percent O_2) when using landfill gas. For CO emission levels, the standard is not fuel specific and varies between 2 and 2.7 g/bhp-hr (250-330 ppmvd at 15 percent O_2).

For gas turbines, the most stringent BACT determination for use of either landfill or digester gas that has appeared in a preconstruction permit is for Joint Water Pollution Control Plant in Carson. The permit established limit of 25 ppmvd at 15 percent O2 for NOx emissions. The determination is for three Solar Mars 90 (10 MW) combined cycle plant generating a total of 34.8 MW. The level is achieved with water injection. In addition, the BACT determination for the gas turbine at UCLA is not applicable because the turbines at UCLA burn a mixture of landfill gas and natural gas with the majority of the fuel being natural gas.

D. Emission Levels Achieved in Practice

Tables B-7 and B-8 list the most stringent emission levels achieved, based upon emission testing, for NOx, VOC, and CO, for engines used in landfill gas applications and engines or turbines used in digester gas applications respectively. For the engines used in landfill applications, the engines tested range from 850 hp to 4,300 hp. Similarly, for digester gas fueled engines, the tested engines range from 260 hp to 1,400 hp. Some of these engines were listed in the previous section.

In general, the examples listed demonstrate compliance with the district BACT determination for NOx of 0.6 g/bhp-hr. For landfill gas fueled engines, the results of the testing varied from 0.31 to 0.48 g/bhp-hr of NOx, which demonstrates the variability of the landfill gas composition on the engine's NOx emissions. Similar results were seen for engines using digester gas in that results of the testing varied from 0.36 to 0.52 g/bhp-hr of NOx. Note that the tests for the engines at the City of Stockton indicates that emissions of NOx are higher with natural gas than with digester gas--probably resulting from the lower Btu content of the digester gas. In

Table B-7
Emission Source Test Results for Engines Using Landfill Gas

Facility Name	District / State	Description of Basic Equipment	Method of control	Date Tested	Engine tested	Measured (g/bhp-hr)* NOX	VOC	CO
County of Sacramento--Kiefer Landfill	Sacramento Metropolitan AQMD	(3) 4,230 bhp Caterpillar G3616 lean-burn engine driving a 3 MW electric generator for a total of 9 MW	Lean-burn technology	1/00	#1	0.39 or 28 ppmvd	<0.15 or <50 ppmvd	1.73 or 209 ppmvd
					#2	0.41 or 31 ppmvd	<0.13 or <50 ppmvd	1.7 or 214 ppmvd
					#3	0.48 or 33 ppmvd	<0.15 or <50 ppmvd	1.9 or 213 ppmvd
Minnesota Methane --Lopez Landfill	SCAQMD	(2) 4,235 bhp Caterpillar G3616 lean-burn engine driving a 3.05 MW electric generator	Lean-burn technology	3/99	#1	0.41 or 27 ppmvd	0.05 or 9 ppmvd	1.73 or 189 ppmvd
					#2	0.56 or 35 ppmvd	0.09 or16 ppmvd	1.92 or 200 ppmvd
Minnesota Methane Tajiguas Corporation--Tajiguas Landfill	Santa Barbara Co. APCD	4,314 bhp Caterpillar 3616 lean-burn engine driving a 3 MW electric generator	Lean-burn technology	1/01	85-100 load	0.31 or 24 ppmvd	0.1 or 6 ppmvd	1.59 or 211 ppmvd
					75% load	0.27 or 20 ppmvd	0.22 or 14 ppmvd	1.8 or 213 ppmvd
					62% load	0.2 or 15 ppmvd	0.27 or 17 ppmvd	1.8 or 212 ppmvd
Minnesota Methane--Corona	SCAQMD	850 bhp Caterpillar G399TA lean-burn engine driving a generator	Lean-burn technology	1997	NA	0.6	0.2	1.5
Ogden Power Pacific--Stockton	SJVUAPCD	1,100 bhp Cooper 8GTLA lean-burn engine driving a generator	Lean-burn technology	12/00	NA	0.45 or 28 ppmvd	0.32 or 58 ppmvd	3.9 or 399 ppmvd

* unless otherwise indicated; ppmvd expressed at 15% O2

Table B-8
Emission Source Test Results for Engines or Turbines Using Digester Gas

Facility Name	District / State	Description of Basic Equipment	Method of control	Date tested	Engine tested	Measured (g/bhp-hr)*		
						NOX	VOC	CO
City of Stockton	SJVUAPCD	(3) 1,408 bhp Waukesha L7042GLD digester/natural gas lean-burn engine generating 1.05 MW each for a total of 3.15 MW; cogeneration: electricity used onsite and hot water generated for digester	Lean-burn technology	10/00 digester gas	#3	0.52 or 30 ppmvd	<0.16 or <26 ppmvd	2.6 or 243 ppmvd
				10/00 digester gas	#4	0.45 or 26 ppmvd	<0.16 or <25 ppmvd	2.5 or 233 ppmvd
				10/00 digester gas	#1	0.49 or 31 ppmvd	<0.14 or <25 ppmvd	2.4 or 245 ppmvd
				10/00 NG	#3	0.58 or 36 ppmvd	<0.16 or <27 ppmvd	2.5 or 255 ppmvd
				10/00 NG	#4	0.47 or 29 ppmvd	<0.155 or <27 ppmvd	2.5 or 250 ppmvd
				10/00 NG	#1	0.54 or 35 ppmvd	<0.14 or <27 ppmvd	2.5 or 266 ppmvd
Hemet/San Jacinto Regional Water Reclamation Facility--San Jacinto	SCAQMD	260 bhp Caterpillar G379 SI-TA-HCR spark ignition digester gas-fired engine, with pre-stratified charge system driving a aeration blower	Pre-stratified charge system	5/00	NA	0.487 or 32 ppmvd	0.539 or 101 ppmvd	1.524 or 163 ppmvd

Table B-8
Emission Source Test Results for Engines or Turbines Using Digester Gas

Facility Name	District / State	Description of Basic Equipment	Method of control	Date tested	Engine tested	Measured (g/bhp-hr)*		
						NOX	VOC	CO
Joint Water Pollution Control Plant--Carson	SCAQMD	(3) Solar Mars 90 turbines generating 9.9 MW (113 MMBtu/hr) with heat recovery steam generator and one 5.1 MW steam turbine for total of 34.8 MW	Water injection / SCR	12/99	Turbine #1	19.3 ppmvd	NA	12 ppmvd
					Turbine #2	21.5 ppmvd	NA	8 ppmvd
					Turbine #3	21.2 ppmvd	NA	19 ppmvd
Orange County Sanitation District--Huntington Beach	SCAQMD	4,166 bhp Cooper LSVB-16-SGC lean burn engine driving a 3 MW generator with heat recovery steam generator	Lean burn technology	6/96	NA	0.36	0.2	2
South East Regional Reclamation Authority--Dana Point	SCAQMD	636 bhp Waukesha 2895GL, lean burn digester gas/natural gas-fired engine driving blower with heat recovery to digester tanks	Lean burn technology	6/96	NA	0.36	0.2	2

* unless otherwise indicated; ppmvd expressed at 15% O2.

addition, the engines at the City of Stockton were well under the BACT determination of 1.25 g/bhp-hr.

For the other pollutants, there has been similar variation in emission levels. Some of this variation can be explained by operators striving to meet stringent NOx levels which can adversely affect CO or VOC emissions. For landfill gas fueled engines, VOC emission levels have varied from 0.05 to 0.32 g/bhp-hr, and for digester gas, VOC emission levels have varied from 0.2 to 0.5 g/bhp-hr. Similarly, for CO emission levels, the emission levels have varied from 1.6 to 3.9 g/bhp-hr for landfill gas and, the emission levels have varied from 1.5 to 2 g/bhp-hr for digester gas.

For gas turbines using a waste gas, Joint Water Pollution Control Plant, mentioned above, achieved between 19 and 22 ppmvd at 15 percent O_2 for NOx levels and 8 to 19 ppmvd at 15 percent O_2 for CO levels.

E. Discussion and Recommendation

A review of the BACT levels contained in district preconstruction permits and the emissions achieved in practice support a BACT level of 0.6 g/bhp-hr for NOx emissions from reciprocating engines combusting landfill or digester gas.

The most stringent BACT determination in a preconstruction permit for NOx is 0.31 g/bhp-hr. This determination is for a Deutz TBG620 lean burn engine at the Badlands Landfill in Riverside. The determination is based upon a vendor guarantee. However, as discussed above, this determination is much lower than other BACT determinations for the same type of source. All the other recent determinations contained in the preconstruction permits range from 0.55 to 0.6 g/bhp-hr, except for a determination for Waukesha engines in Stockton. These engines were permitted at 1.25 g/bhp-hr--the previous BACT level, but as discussed below, the emissions achieved in practice were much lower.

As discussed above, the NOx emissions achieved in practice ranged from 0.31 to 0.52 g/bhp-hr for either landfill or digester gas. The most stringent BACT level achieved in practice for a reciprocating engines using waste gas is 0.31 g/bhp-hr for NOx, 0.1 g/bhp-hr for VOC, and 1.59 g/bhp-hr for CO. This determination is for a Caterpillar G3616 lean-burn engine at the Tajiguas Landfill in Santa Barbara. NOx emissions for the same engine at other landfills varied from 0.39 to 0.56 g/bhp-hr, indicating the influence of the quality of the landfill gas on NOx emissions. For the Waukesha engines in Stockton, the engines were tested at 0.45-0.52 g/bhp-hr for digester gas only--some 60 percent lower than the limit contained in the permit.

For gas turbines, the most stringent BACT determination for use of a waste gas that has appeared in a preconstruction permit is for the Joint Water Pollution Control Plant in Carson. The permit established a limit of 25 ppmvd at 15 percent

O_2 for NOx emissions for each of the three Solar Mars 90 turbines. Subsequent testing indicated this level is achieved in practice.

Based on the above, the ARB staff recommends the following levels for a reciprocating engine using a waste gas: 0.6 g/bhp-hr for NOx, 0.6 g/bhp-hr for VOC, and 2.5 g/bhp-hr for CO. These levels are consistent with the SCAQMD's BACT guidance for this category of sources. In addition, the VOC and CO are set at higher levels to allow operators the flexibility in combustion modifications to meet stringent NOx levels. For gas turbines using a waste gas, the ARB staff recommends that the BACT level reaches 25 ppmvd at 15 percent O_2 for NOx emissions.

Appendix C
Procedure for Converting Emission Data to lb/MW-hr

Engines

Engine emission standards are typically expressed in terms of ppmv or in grams/brake horsepower-hour. Given below are factors to convert from ppm to grams/brake horsepower-hour and from grams/brakehorsepower-hour to pound/megawatt hour.

The resulting answers will be approximate values since various default assumptions were used to develop natural gas default factors. The efficiency of the engine has the greatest affect on the concentration (ppmvd) to mass emission rate conversion (g/bhp-hr), which can vary from 20 to 40 percent. In the calculations below, the efficiency is proportional to the engine brake specific fuel consumption.

PPM to GM/Bhp-hr

$$\text{Concentration in exhaust by volume (dry) (ppmvd)} = \frac{\text{volume of pollutant (Vp)}}{\text{volume of exhaust (Ve)}} \times 10^6$$

Vp = emission factor (g/bhp-hr) x horsepower x (1/molecular weight) x molar volume x conversion factors

Ve = F-factor for exhaust volume x excess air correction x engine brake specific fuel consumption x horsepower x conversion factors

These factors can be reduced to: ppmvd = (gm/Bhp-hr) * factor

Reciprocating Engines, natural gas fueled

Pollutant	Factor
NOx	57-59
VOC	163-170
CO	93-97

Values taken from California Air Pollution Control Officers Association (CAPCOA) report: Portable Equipment Rule Piston IC Engine Technical Reference Document, 1995.

Lean-burn Engines, natural gas fueled

Pollutant	Factor
NOx	80
VOC	212
CO	123

Factors provided from Waukesha

GM/Bhp-hr to Lb/MW-hr

Gm/Bhp-hr x 3.07 = lb/MW-hr

- Includes 95% factor for generator efficiency
- Conversion factors for grams to pounds and brake horsepower to watts

Gas Turbines

lb/MW-hr = emission rate (lb/MMBtu) x 3.413 KW/Btu / efficiency

2.5 ppmvd = 0.0093 lb/MMBtu for NOx
2 ppmvd = 0.0027 lb/MMBtu for VOC
5 ppmvd = 0.013 lb/MMBtu for CO

efficiency for central station power plant is 50%

Appendix D
Quantifying CHP Benefits

The following is a recommended procedure for district staff to include the benefits of combined heat and power (CHP) toward compliance with the emission level of central station power plants equipped with BACT. This credit cannot be used to avoid satisfying district BACT requirements or in quantifying an emission offset credit.

The credit for CHP is given to those installations that meet the following criteria: 1) design to achieve a minimum efficiency of 60% in the conversion of the energy in the fossil fuel to electricity and process heat; 2) design to achieve an annual average efficiency of 75% in the conversion of the energy in the fossil fuel to electricity and process heat; and 3) BACT requirements are satisfied for the size and class of electrical generation technology. In addition, efficiency determinations do not include time periods for startup, shutdown, and when the facility is not operated.

If all the above qualifications are satisfied, credit should be granted in form of allowing the process heat be added to the total energy production at the facility at the rate of 1 MWh for each 3.4 million Btu of process heat.

Lb/MW-hr = emissions (lb/hr) / [MW (electrical) + MW (process heat)]

EXAMPLE

Project with fuel input of 16 MW provides 5 MW of electrical output and an equivalent process heat requirement of 7 MW. The process heat requirement can dip to 5 MW. Emissions are at 5 ppmv at 15% O_2 or 0.25 lb/MW-hr.

Minimum overall efficiency:	62%
Average overall efficiency:	75%
Lb/MW-hr:	0.25
Lb/MW-hr with CHP credit:	0.1

Suggested Additional Permit Application Information for CHP final compliance credit

- Quantifying fuel use:

  --For a gas turbine based systems, include separately the average fuel use expected for the gas turbine, and if applicable, the average fuel use expected for using duct burners. Provide information on a daily and annual basis.
  --For a reciprocating engine, provide brake specific fuel consumption and the average capacity the engine will operate at. Provide information on a daily and annual basis.

- Quantifying electrical energy use

  --Estimate average electricity production. If maximum capacity is cited for electrical production, documentation should be provided (for example, a contract with an utility). This value will be convert to Btu/hr based upon Btu in one kilowatt hour—3,414. Power output is expected output at generator terminals.

- Quantifying process heat requirements

  --Description of process heat requirements and variation of the process heat requirements over a year. Description should identify processes or equipment using the thermal energy and the amounts of process heat needed (in terms of million Btu/hour). At a minimum, provide minimum, maximum and annual average values.

  --information on process heat delivered:

  - For each process heat stream, provide the inlet and outlet temperatures for the heat exchanger or heat recovery generator. For example, for an engine where process heat is taken from both the water jacket and the exhaust gases, this information should be provided for the heat extracted and used from the water jacket and the exhaust gases.

  - Process heat credit will be based upon the heat used by a process. Any energy associated with steam being condensed in a condenser is not counted toward the process heat of the CHP calculation.

<u>Overall Minimum Efficiency Determination</u>

- For process heat requirements, the minimum process heat requirements (Btu/hr) should be used. The minimum process heat requirement does not include thermal energy from supplemental fuel firing.
- For electricity generation, use the average electrical generation (convert to Btu/hr).
- For fuel input (Btu/hr), do not include supplemental fuel firing.

Minimum efficiency = [electricity production + process heat]/[fuel energy input]

<u>Overall Annual Average Efficiency Determination</u>

- For process heat requirements, use the total process heat requirement (Btu/hr). Supplemental fuel firing should be included.
- For electricity generation, use the total electrical generation (convert to Btu/hr).
- For fuel input, supplemental fuel firing should be included.

Minimum efficiency = [electricity production + process heat]/[fuel energy input]

Appendix E
Sample Permit Conditions

Commissioning Period

1. Emissions from the commissioning period shall be minimized.

2. The control system shall be installed, adjusted and operated to minimize emissions. The minimum and maximum catalyst temperature for optimum operation shall be established with a source test.

3. The total number of firing hours without abatement shall not exceed XXX hours during the commissioning period. Emissions released during the commissioning period shall count toward quarterly and/or annual emission limits.

4. Upon completion of the commissioning period, a source test should be conducted to determine compliance with applicable emission limits.

Source Testing - Engines

<u>Greater than100 horsepower</u>

1. The permittee shall have the unit's emissions tested no less than once every 36 months. Testing shall be performed by an independent testing contractor at the unit's expected maximum operating load.

2. Prior to conducting testing associated with annual tests, the permittee shall contact the district compliance staff. Written notification shall be received no less than 15 calendar days prior to the tests. The test report and results shall be submitted to the district compliance staff within 45 days after the tests.

3. Emission testing shall be conducted with district approved test methods.

4. A district-approved portable analyzer shall be used at least quarterly to demonstrate compliance with emission limits of this permit. The intend of the use of a portable analyzer is to ensure the proper operation of air pollution control systems. Measurement results, both the date of the measurement and the measurement results, shall be recorded in the unit's operating log. If the measurements with the portable analyzer exceed the applicable levels in this permit, the permittee shall evaluate the performance of the control equipment to determine if the catalyst needs servicing/replacement or an emission test is necessary. (not applicable to engines equipped with CEM).

<u>100 horsepower and less</u>

1. A district-approved portable analyzer shall be used at least quarterly to demonstrate compliance with emission limits of this permit. The intend of the use of a portable analyzer is to ensure the proper operation of air pollution control systems. Measurement results, both the date of the measurement and the measurement results, shall be recorded in the unit's operating log. If the measurements with the portable analyzer exceed the applicable levels in this permit, the permittee shall evaluate the performance of the control equipment to determine if the catalyst needs servicing/replacement or an emission test is necessary.

2. The district may request the permittee to source test the engine. Testing shall be performed by an independent testing contractor at the unit's expected maximum operating load. Testing will not be requested more often than once every 36 months, unless district inspectors determine monitoring program was not properly implemented or monitoring results were misrepresented.

3. Any emission testing shall be conducted with district approved test methods.

Monitoring

1. An operating log shall be kept on the premise. At a minimum, the log shall include: a running total of the hours of operation, preventative and corrective maintenance on the engine and the air pollution control equipment and record any minor equipment modifications.
2. The permittee shall monitor and record the catalyst inlet, outlet temperature, and injection rate of the reducing reagent [for SCR system only] at least once per week. The date and time of these measurements shall also be recorded. All exceedances outside the temperatures for maximum emission control shall be recorded in the log. The monitoring is not required if the unit is not in operation. Records shall be maintained on the premises for at least five years.